

COMMITTEE WORKSHOP  
BEFORE THE  
CALIFORNIA ENERGY RESOURCES CONSERVATION  
AND DEVELOPMENT COMMISSION

In the Matter of: )  
 )  
Preparation of the 2007 ) Docket No.  
Integrated Energy Policy ) 06-IEP-1D  
Report (2007 IEPR) )  
\_\_\_\_\_ )

CALIFORNIA ENERGY COMMISSION  
HEARING ROOM A  
1516 NINTH STREET  
SACRAMENTO, CALIFORNIA

THURSDAY, JUNE 7, 2007

9:00 A.M.

Reported by:  
Peter Petty  
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

James D. Boyd

Jeffrey D. Byron

John Geesman, Associate Member

ADVISORS PRESENT

Susan Brown

Melissa Jones

Kevin Kennedy

Gabriel Taylor

Tim Tutt

STAFF and CONTRACTORS PRESENT

Leon D. Brathwaite

Catherine Elder, RW Beck, Inc.

James Fore

Youssef Hegazy, PhD, RW Beck, Inc. (via telephone)

James T. Jensen, Jensen Associates

Dale Nesbitt, PhD, Altos Management Partners, Inc.

Michael G. Purcell

Angela Tanghetti

Ruben Tavares

Lorraine White

Bill Wood

ALSO PRESENT

Bevin Hong Jr., TransCanada

Robert S. Cowden, Pacific Gas & Electric Company

David L. Arthur, PhD, Redding Electric Utility

Steven R. Schiller, University of California,  
California Institute for Energy and Environment

Mark P. Sweeney, California Natural Gas Vehicle  
Coalition

Richard Myers, California Public Utilities  
Commission

Jill Scotchi, Pacific Gas & Electric Company

Kevin Billings, Kern River Gas Transmission  
Company

Rory Cox, Pacific Environment

Alvin Pak, Sempra Energy (Sempra LNG)

Herbert S. Emmrich, Southern California Gas  
Company and San Diego Gas & Electric

Gary M. Yee, Air Resources Board

George Clavier, Pacific Gas & Electric Company

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## 1 P R O C E E D I N G S

2 9:05 a.m.

3 PRESIDING MEMBER PFANNENSTIEL: We can  
4 be underway. This is a workshop of the Integrated  
5 Energy Policy Report Committee on Natural Gas  
6 Market Assessment. It is, as you can see, of  
7 great interest to the Commission. We have four of  
8 us here to participate in this. I'm Jackie  
9 Pfannenstiel, the Commission Chair and the  
10 Presiding Member of the Integrated Energy Policy  
11 Report Committee. To my left is Commissioner Jeff  
12 Byron, to my right Commissioner Boyd. To his  
13 right, Commissioner John Geesman, and to  
14 Commissioner Geesman's right his staff advisor,  
15 Melissa Jones.

16 A full agenda that I think everybody has  
17 in front of you so why don't we begin. Ruben.

18 MR. TAVARES: Good morning,  
19 Commissioners. As you know we have a full agenda  
20 for today. Hopefully we'll enjoy it. Before we  
21 start some housekeeping items. This workshop is  
22 being tape-recorded and also webcast on the  
23 Internet.

24 Phone calls, you can make a phone call  
25 to 1-800-857-6618. The passcode is IEPR and the

1 leader is Lorraine White. Those on the phone  
2 please identify yourselves for the record when  
3 making a comment or asking a question. And please  
4 put your telephone on mute while waiting.

5 Otherwise, you know, any noises on your end will  
6 broadcast in the hearing room.

7 For those in the room, the restrooms and  
8 telephones are on the patio to the left as you  
9 leave the front door of the hearing room. Coffee,  
10 beverages are upstairs on the second floor. And  
11 also we are asking everybody to please silence  
12 your cell phones. If you need to make a call  
13 please go outside to the patio.

14 Agenda, copies of the preliminary report  
15 and presentations are on the table outside.  
16 Hopefully you will get a copy and follow the  
17 presentations. We have scheduled through around  
18 3:30 this afternoon. If we finish early we will  
19 leave early but hopefully no later than 3:30.

20 When making a comment please go to the  
21 telephone, identify yourself and pose a question.

22 Again, we have the IEPR Committee and  
23 also the Natural Gas Policy Committee with us.  
24 Commissioner Pfannenstiel, would you like to make  
25 a comment?

1                   PRESIDING MEMBER PFANNENSTIEL: I have  
2 no opening comments. Other Commissioners?

3                   COMMISSIONER BYRON: No.

4                   PRESIDING MEMBER PFANNENSTIEL: No? Go  
5 ahead.

6                   MR. TAVARES: No comments, okay.

7                   First we are going to have Lorraine  
8 White. She is going to make a presentation on how  
9 the Natural Gas Assessment Report actually fits  
10 into the overall IEPR. So Lorraine.

11                   MS. WHITE: Good morning, everyone. My  
12 name is Lorraine White and I am a program manager  
13 for the Integrated Energy Policy Report  
14 proceeding.

15                   Today's workshop is a very important  
16 part of the record on which the Energy Commission  
17 will be building the 2007 Integrated Energy Policy  
18 Report. The relationship between natural gas  
19 supplies, price, infrastructure and demand has an  
20 impact on not only the availability of this  
21 resource to meet the needs of consumers but it  
22 also is related to the electricity sector, the  
23 effects of the availability of supplies and demand  
24 there as well as price.

25                   As we heard last week the natural gas

1 resources are also an important part of emerging  
2 transportation alternative fuels and has a lot of  
3 interrelationships with other types of energy  
4 markets.

5 The Integrated Energy Policy Report  
6 requires the Energy Commission to look at, assess  
7 and forecast supply, demand and price for various  
8 energy resources and look at the interrelationship  
9 between those resources and markets.

10 This particular IEPR is looking not only  
11 at the electricity market, the natural gas market,  
12 petroleum markets and other fuel markets that meet  
13 the demands and needs of California and the West  
14 but we are also looking at topics related to  
15 efficiency. How these demands actually occur in  
16 California, in particular how land uses are  
17 affecting demand and supply and infrastructure.  
18 Looking at the different alternatives, looking at  
19 emerging technologies, research opportunities.  
20 The drivers that affect cost and what types of  
21 issues we'll be facing in the future, particularly  
22 in a post-AB 32 world.

23 From these assessments and forecasts we  
24 are going to be developing policy recommendations  
25 that will be addressing the various types of

1 issues exposed by these forecasts and assessments  
2 related to the adequate supplies and resource  
3 provision to California to meet its needs. We  
4 rely on the input of various groups and entities  
5 to ensure that we have a robust assessment and  
6 forecast on which to build these recommendations.  
7 We look to market participants and other agencies  
8 to participate in this proceeding so that we can  
9 come up with the best assessment and forecast as  
10 well as recommendations as possible.

11 The legislation requires that we revisit  
12 these assessments and forecasts every two years  
13 and in intervening years develop updates on the  
14 most particular and salient issues of the time.  
15 In this particular instance we have benefited a  
16 great deal from input from various market  
17 participants, cooperative participation by the PUC  
18 and the CA-ISO and we look forward to today  
19 continuing that dialogue.

20 We are at a critical part in the  
21 proceeding. Right now we are developing a lot of  
22 the draft reports that document the assessments  
23 and forecasts that we are doing. Today's workshop  
24 is an example of that.

25 As we refine these reports and

1 assessments with the input we are getting from  
2 various parties we hold a lot of the workshops to  
3 try and get that input to refine it, to build off  
4 of previous discussions. For example, the March 6  
5 workshop n the staff's assessment proposal and  
6 methodologies. But then also to produce final  
7 documents on which we will actually craft the  
8 Committee Integrated Energy Policy Report.

9 In late August we will be publishing  
10 that document and having hearings on that document  
11 in September. With the goal, of course, to have  
12 the whole Commission adopt the 2007 Integrated  
13 Energy Policy Report by October 24.

14 All of the information we are generating  
15 as part of this proceeding we make available on  
16 the Commission's website. Any questions or  
17 comments that you might have which you don't  
18 necessarily know quit how to fit into the record  
19 you can always contact me. Also to get  
20 information about other related topics that the  
21 Commission is looking at as part of this  
22 proceeding. Particularly when it comes to natural  
23 gas I refer you Ruben Tavares.

24 Just for your information and related to  
25 the idea that we are developing an Integrated

1 Energy Policy Report proceeding, there are some  
2 other workshops that we will be holding in which  
3 natural gas will be discussed. And in particular  
4 I will draw your attention to the scenario  
5 workshops that are coming up later this month and  
6 in July. That information can also be found on  
7 the website.

8 If there's any questions I'd be happy to  
9 answer them. Thank you.

10 MR. TAVARES: Okay, so what is the  
11 purpose of the workshop today? As you know we are  
12 presenting a preliminary assessment report on  
13 natural gas and we are soliciting comments and  
14 suggestions from the public and the Commissioners  
15 on our results. We, the staff of the Energy  
16 Commission, in conjunction with contractors and  
17 consultants, we developed this forecast. So we  
18 are asking for all your suggestions and comments.

19 As Lorraine mentioned a few minutes ago,  
20 we are going to put together the final report. We  
21 are planning to have the report by the end of  
22 July. Then there is going to be another  
23 proceeding by the middle of August. We are going  
24 to try to integrate, you know, the results that we  
25 have on natural gas with the scenario project.

1 But we will talk a little bit more about that, you  
2 know, by the end of this workshop.

3 On March 26 of this year we conducted a  
4 workshop. It was a staff workshop to request  
5 input on the staff's assumptions that we were  
6 planning to use in our model. The model that we  
7 lease from Altos is the North American Regional  
8 Model, Gas Model.

9 And we received some comments and we  
10 discussed these comments with the Commissioners  
11 and some of the advisors and we incorporated some  
12 of those comments into our results. So what you  
13 use today is going to be a reference case that we  
14 developed given those assumptions. So we are  
15 asking again for more comments today on our  
16 results.

17 As a difference from the past, in the  
18 past we had more or less a single point forecast  
19 in our natural gas assessment. In this 2007  
20 natural gas assessment we are putting less  
21 emphasis on a point forecast and more on some  
22 alternatives. Again, our assumptions and inputs  
23 are just the set of assumptions that we think are  
24 the best. However, those assumptions and those  
25 variables can change and if they change our output

1 will change.

2 As I mentioned before we used NARG, the  
3 North American Regional Gas Model, to develop the  
4 reference case. To determine demand, supply,  
5 infrastructure and prices of natural gas.

6 Staff also used the NARG model to run  
7 four different sensitivities. In other words we  
8 just modified one variable to see what kind of  
9 results we would get. We had four of them, two on  
10 the oil price, one was using the high oil price  
11 another one low oil price, and two additional,  
12 LNG, liquified natural gas, one facility in  
13 Southern California and another one in Oregon.  
14 Those were separate, separate sensitivities.

15 We also received assistance from RW  
16 Beck. They helped us analyze the assumptions and  
17 variables that we had in our reference case and  
18 they gave us some potential alternatives. And we  
19 will have a presentation this afternoon on, you  
20 know, what are those alternatives and  
21 uncertainties involved in forecasting, again,  
22 demand, supply, infrastructure and prices of  
23 natural gas.

24 The Commission also hired Mr. Jim  
25 Jensen. He is a very well-known expert on

1       liquified natural gas. He is going to make a  
2       presentation this morning on the current status of  
3       worldwide natural gas supply, demand and  
4       transportation cost.

5               Mr. Jensen developed the base case, what  
6       he calls reference case scenario, and two  
7       alternative scenarios. One, a high scenario  
8       reflecting market optimism on liquified natural  
9       gas, and a second scenario reflecting concern on  
10      the supply side of liquified natural gas.

11             Our first presentation is going to be on  
12      liquified natural gas and Mr. Jim Jensen is going  
13      to present his results of a study that he  
14      conducted so far. So, Mr. Jensen.

15             MR. JENSEN: Good morning. I am pleased  
16      to be invited here this morning to discuss the  
17      study work that we have done for the Commission on  
18      liquified natural gas, a topic that, of course, is  
19      of great deal of interest today.

20             Until the mid-1990s world LNG trade was  
21      really defined by two characteristics. It was  
22      largely Pacific Basin trade. As recently as 1994,  
23      77 percent of all LNG supply originated in the  
24      Pacific Basin, 74 percent of all LNG demand was in  
25      the Pacific Basin. In fact, interesting enough at

1 that point the gas utilities in Tokyo, Osaka and  
2 Nagoya accounted for half of world LNG trade.

3 But that began to -- The second part of  
4 the pattern was that it was based on long-term  
5 contracts which were essentially destination  
6 inflexible. They linked specific buyers and  
7 specific sellers and you knew where the stuff was  
8 coming from, you knew where it was going.

9 But that whole pattern began to change  
10 in the late 1990s. Demand began to surge as gas-  
11 poor countries such as Spain, Turkey, China, India  
12 got interested in gas-fired combined cycle  
13 generation and looked to LNG for gas supply.

14 And at the same time you began to see  
15 the, you began to see the traditional consumers in  
16 North America and Europe finding the limitations  
17 on their traditional sources of domestic and  
18 pipeline supply. So they became interested in LNG  
19 as well. This brought forth a burst of new  
20 capacity additions which came in in the Atlantic  
21 Basin and in the Middle East.

22 Basically the demand increases have  
23 changed the structure as well. The traditional  
24 long-term contract fell victim to the worldwide  
25 restructuring of the gas industry. The

1 traditional contract was based on the assumption  
2 that it was a sharing of risk between buyer and  
3 seller. And the comment was essentially, the  
4 buyer takes the volume risk by absorbing a take or  
5 pay contract, the seller takes the price risk in a  
6 price clause. And that essentially was risk-  
7 sharing mechanism.

8 As North America restructured its  
9 industry, deregulated and went to gas-to-gas  
10 competition it became almost impossible to sell an  
11 oil-link contract in a gas-to-gas competitive  
12 market so that structure really went by the  
13 boards. And it has gone by the boards in the UK,  
14 which has also restructured its industry.

15 But that has had a subtle effect because  
16 in a sense what has happened is that if you link  
17 the long-term contract price clause to a gas  
18 market indicator like Henry Hub in the US or to  
19 the National Balancing Point in the UK, it makes  
20 it much simpler for the buyer to absorb risk  
21 because if he doesn't like the cargo when it  
22 arrives he can turn around and sell it in the  
23 market.

24 So risk has migrated upstream to the  
25 sellers. And the sellers have responded in many

1       ways by a new form of operation in which  
2       essentially they contract, what I call self-  
3       contracting for supply at the well head, and they  
4       move it through their own outlets downstream. So  
5       in other words, a shell having participation in a  
6       particular LNG plant will essentially buy the  
7       stuff off that and move it to its affiliates in  
8       the US or Europe.

9               A small, short-term market has  
10       developed, a spot market, maybe 12, 14 percent of  
11       total. And the fact that the self-contracting  
12       exists means that the sellers are much more able  
13       to move volumes to the markets that want it. For  
14       example, ABG has access to capacity in Trinidad,  
15       it has access to capacity in Egypt, it has  
16       terminal capacity that it controls in the US, it  
17       has terminal capacity that it controls in the UK,  
18       and it can look at the National Balancing Point  
19       price or the Henry Hub price and decide where to  
20       divert its internal supplies.

21              What that has done essentially is  
22       created a much more flexible and global market.  
23       The Pacific Basin is not really quite a part of  
24       that yet, and yet because the Middle East is the  
25       center for shipping east and west, in effect what

1       you have is a price arbitrage between the Pacific  
2       Basin market and the Atlantic Basin market via the  
3       Middle East. So what we now have is a global gas  
4       market in which pipelines compete with LNG and the  
5       price signals are moved around the world by LNG  
6       pricing.

7               The current outlook for LNG has become  
8       highly uncertain because of a number of reasons.  
9       First of all there is an unexpectedly sharp  
10      increase in demand, particularly in North America,  
11      Spain and the UK. These markets decided they  
12      wanted LNG fairly quickly and the demand increased  
13      very rapidly.

14             At the same time the normal lag in  
15      putting projects together, including approvals and  
16      plant construction four years or more meant that  
17      supply could not respond quickly to the increase  
18      in demand. And what we have essentially had,  
19      we've created a shortage, a worldwide shortage of  
20      supply because of the lags between demand and  
21      supply.

22             The fact that the surge in plant  
23      construction came about essentially overwhelmed  
24      the capability of the sophisticated design  
25      constructors and equipment suppliers who supply

1 the business and what we have had is an almost  
2 unprecedented increase in costs.

3 It was fashionable until several years  
4 ago to talk about the fact that LNG costs were  
5 steadily coming down. And at that point it began  
6 to look as if the target was something like for an  
7 LNG plant, \$200 of capital cost per ton of  
8 capacity. Now people are talking \$400 to \$600 a  
9 ton as the norm but it is a very uncertain and  
10 very unstable market.

11 And there are several projects that have  
12 come in either with cost overruns or for new bids  
13 that range between \$1,000 and over \$1,200 a ton, a  
14 very dramatic increase in costs. I mean,  
15 essentially what's happened, there are a limited  
16 number of people who know how to do these things  
17 very well and they don't answer the telephone  
18 anymore because the demand is so high. And this  
19 has caused, obviously, some very serious problems.

20 The fact that we have had a sharp rise  
21 in oil and other energy prices raises questions  
22 about demand response. Are we going to get demand  
23 elasticity, are we going to get a fall-off in  
24 demand so we'll forecast change. And also what  
25 happens to interfuel competition? Coal has not

1        responded, for example, in China at nearly the  
2        rate that gas has responded. So if you look at  
3        the Chinese demand you say, how is the balance  
4        between gas and coal in China been shifted?

5                The political reaction to global warming  
6        and how it will affect competition between coal  
7        and gas for power generation. An important  
8        indication of China. China is now about to pass  
9        the US as a carbon emitter and obviously a lot of  
10       that is because they use coal for power  
11       generation. But at the moment with the prices  
12       what they are the Chinese are economically  
13       dedicated to coal. And until they decide to clamp  
14       down on coal use gas will be affected.

15                And then there are the questions of  
16        geopolitical issues that will determine when and  
17        how LNG projects will go forward in supplying  
18        countries. And those are very important issues.

19                And finally, LNG is sensitive to small  
20        changes in the world's gas supply/demand balances.  
21        Essentially it is a small part of the gas supply/  
22        demand balance. And in a country importing LNG,  
23        if there is a small change in a little bit of LNG  
24        and a lot of domestic production, like in the US,  
25        a small change in either demand or supply not

1 matched by the other has a very powerful leveraging  
2 effect on the demand for LNG. All of these cause  
3 uncertainties that are things you have to deal  
4 with.

5 My study addressed these issues by  
6 utilizing three illustrative scenarios: First a  
7 base or reference case, second a high case  
8 reflecting earlier market optimism, and third, a  
9 low case reflecting concerns about supply.

10 Forecasts in the early 2000s tended to  
11 be very optimistic about the demand for gas and  
12 particularly about LNG. If you can generalize  
13 about forecasts in the middle 1990s, world  
14 forecasts tended to become much more optimistic  
15 about natural gas as the enthusiasm for gas-fired  
16 power generation took hold.

17 And at that point the assumption was  
18 that there was for countries that had domestic  
19 supplies, significant domestic supplies like the  
20 US or like parts of Europe, that there was enough  
21 domestic supply to absorb or to handle this  
22 increased growth and demand. So at that point if  
23 you look at, for example, the EIA projections of  
24 the US, LNG did not play a big role in their  
25 estimates in the late 1990s.

1           Then as concerns for supply began to  
2       develop the forecasts tended to continue the  
3       growth and demand but assumed that LNG would  
4       replace the loss of local supply. So there was a  
5       big increase in LNG forecasts. A lot of optimism  
6       about LNG.

7           More recently with the increases in  
8       costs and with the facts that prices are much  
9       higher and people are not certain how things will  
10      go ahead, there has been a tendency to scale down  
11      both demand estimates and LNG forecasts. My high  
12      case assumes that the old optimism is still right.  
13      My low case, we're transferring a lot of the new  
14      supply to countries that have geopolitical or  
15      technical issues. And it assumes that some of  
16      those may turn out to be difficult to deal with  
17      and so the low case is pessimistic about supply on  
18      that basis.

19           And here simply are the three scenarios  
20      showing the earlier LNG optimism, the base case  
21      and the current long term supply concern.

22           For at time, as I say, LNG costs were  
23      declining and it was assumed that the trend would  
24      continue and stimulate LNG trade. But that trend  
25      has been dashed by the cost increases from the

1 overloaded project industry.

2           And to illustrate why it's such a  
3 problem it is interesting to look at what I would  
4 call the order book. In this business where  
5 you're looking, the plants that are underway now  
6 may not come on, some of them will not come on for  
7 four years. You can kind of look four years ahead  
8 and treat the next four years as the order book.  
9 In other words, the projects that are due to come  
10 on in the next four years are already in the train  
11 so they are a part of the order book.

12           And if you look historically at the  
13 order book pattern going back in time, each of  
14 these years shows the plants that were designed to  
15 come on stream for the following four years. You  
16 can see how sharply that has increased and caused  
17 tremendous problems in terms of the supply  
18 characteristics of the industry.

19           Now I have maintained some internal,  
20 what I call cookbook models of LNG economics so I  
21 can run them in any project that I want to and I  
22 have them back in time so it is possible for me to  
23 sort of reconstruct the history of what I would  
24 have thought at periods in time in the past. And  
25 this slide simply shows you the -- there we go.

1 This slide shows you an estimate that I might have  
2 made for a movement from Australia to Southern  
3 California in 1996 showing liquefaction costs,  
4 tanker transportation costs and regasification.

5 But costs were coming down. That's the  
6 estimate that might have been made in 2000 with a  
7 significant reduction in cost. By 2003 it was  
8 down again. But as you can see in this estimate  
9 it has gone right back up again. Most of the  
10 increases in the liquefaction costs because  
11 tankers have not been so badly affected.

12 Now I would have to say that is highly  
13 speculative because I talk to a lot of people in  
14 the industry and nobody can agree what has  
15 happened to costs. And I would have to say that  
16 my estimates are probably on the conservative side  
17 because I do not believe that a dramatic increase  
18 such as we have had necessarily carries forward to  
19 the long term. But the current feeling in the  
20 industry is that their prices are even higher.  
21 But as you can see, speculative or not, the idea  
22 that costs are declining is now gone.

23 ASSOCIATE MEMBER GEESMAN: Were those  
24 for actual estimates that you made over the period  
25 of those 11 years or is that you constructing

1       today what you might have said in each of those  
2       years?

3               MR. JENSEN:  Yeah, I mean I have the  
4       models.  I have the assumptions of the model at  
5       the period so I ran the 1996 estimates, I ran the  
6       2000 estimates, I ran it in my current model.  
7       It's the same model but I say, what did I assume  
8       in 1996, what do I assume in 2000.  It's  
9       essentially done that way.

10              ASSOCIATE MEMBER GEESMAN:  Then you've  
11       adjusted those all for 2007 dollars?

12              MR. JENSEN:  No.  They're essentially  
13       dollars, pretty much dollars of the day.

14              ASSOCIATE MEMBER GEESMAN:  Okay.

15              MR. JENSEN:  Okay.  Where will the LNG  
16       come from?  Resources, technology and geopolitics.  
17       The world's reserves of natural gas are very large  
18       and the resource base is large.  More than  
19       adequate to support gas trade far into the future.  
20       And I would have to say that I see no supply  
21       problems in supporting any of my three scenarios  
22       out to 2020.

23              But of those reserves many of those  
24       reserves are either already committed to existing  
25       methods such as domestic markets or committed on

1 international trade. And a big block of those  
2 reserves are what I call deferred reserves. They  
3 are reserves that are associated with oil  
4 production. They may be gas dissolved in oil in  
5 Saudi Arabia that is not going to be produced  
6 until far into the future. They may be big gas  
7 caps in Iran that aren't going to be tapped  
8 because they would affect oil production levels.  
9 They may be gas going in for re-injection.

10 But despite all of that a very large  
11 percentage of the reserves are still available,  
12 are uncommitted. Roughly slightly more than half  
13 of the world's reserves are not committed to any  
14 other use so there are very large reserves,  
15 reserves now existing.

16 But 84 percent of the reserves that are  
17 uncommitted are located either in the Middle East  
18 or in the former Soviet Union and there are  
19 geopolitical or technical issues for both regions.

20 To stress the geopolitical questions.  
21 If you look at 1998 when the LNG business began to  
22 take off and look forward to about 2012, which is  
23 really sort of in train with projects that are  
24 going forward, five countries accounted for 75  
25 percent of world LNG supply.

1           They are Qatar, that itself represents a  
2           third of the total, they are Egypt, Trinidad and  
3           Nigeria, each of which is about ten percent, and  
4           Australia slightly less. So those five countries  
5           all represent the increase in LNG liquefaction  
6           capacity between 1998 and 2012.

7           In my forecast looking out from 2012 to  
8           2020, in my base case there are five countries  
9           that represent 75 percent of it but three of the  
10          countries that are on the first list have dropped  
11          from the second list.

12          Qatar is gone because Qatar has decided  
13          as a matter of policy that once the current major  
14          expansions are complete they are going to sit and  
15          wait for awhile and see what to do and it is not  
16          clear when they'll come back online. Trinidad is  
17          a small country. It has only a limited amount of  
18          area to go looking for gas to support the kind of  
19          growth that it's had. And Egypt may come back, it  
20          depends on how fact exploration goes there.

21          But the countries that have substituted  
22          those three countries are Venezuela, they are  
23          Atlantic Russia and they are Iran. And so in a  
24          sense you have raised in each of those countries  
25          geopolitical issues that really aren't concerns in

1 the first one.

2 And I'd have to say that the leading  
3 country in the out years is Nigeria. And if you  
4 look at Nigeria at the moment what you see is  
5 tremendous civil unrest to the point where bandits  
6 are capturing people off rigs. Some of the major  
7 companies have shut-in their production for  
8 months. It is not an environment that is  
9 conducive to large, up-front capital expenditures.  
10 So these geopolitical issues obviously are a part  
11 of looking forward.

12 Now obviously when I do the difference  
13 between the base case and the low case I am much  
14 more concerned about those. When I do the base  
15 case I assume that today's politics don't last  
16 forever and I think that's a reasonable  
17 assumption.

18 The Pacific Basin markets have been  
19 extremely tight in part because of Indonesia.  
20 Indonesia has been until quite recently the  
21 world's largest LNG supply but it is now the sick  
22 man of Asia. It has very big political problems  
23 and geological problems and at the moment it is  
24 failing to deliver on its contracts. This year  
25 the expectation is that Indonesia will be ten

1 percent below its contract commitments to Japan  
2 and it is in the process of buying spot cargos  
3 from other countries to honor its contract  
4 commitments.

5 But a lot of the future supply in the  
6 Pacific Basin will come from Australia, both from  
7 Western Australia and the Timor Sea.

8 Indonesia will be a mixed bag because  
9 they are having trouble with their existing plants  
10 but they seem committed to go ahead with  
11 expansions such as Tangou, which is going forward.  
12 So there will be growth but there will also be  
13 shrinkage there.

14 But if the Pacific Basin supply is  
15 limited a lot of the future supply for Pacific  
16 Basin markets will have to come from the FSU or  
17 the Middle East.

18 Russia's Sakhalin Island has a great  
19 resource potential but geopolitical issues have  
20 raised questions about how much will be made  
21 available beyond the Sakhalin II Project, which is  
22 the Shell project now under construction.

23 If you followed the press, Sakhalin II  
24 by Shell has had what the economists call the  
25 world's greatest private capital cost overrun in

1 history. Originally budgeted at \$10 billion it is  
2 now budgeted at \$20 billion and is expected to go  
3 to \$23 billion. That has led to a lot of dispute  
4 between the Russians and Shell.

5 A lot of other issues are involved  
6 including the geopolitical ambitions of the  
7 Russian administration. But the fact of the  
8 matter is that Gazprom has now assumed the  
9 operating control from Shell in Sakhalin II. It  
10 is going to go forward but obviously the old role  
11 was changed. And that question is, how will  
12 Sakhalin develop in the future?

13 Now Russia has major policy issues that  
14 have to be resolved in Western Siberia and the  
15 Offshore Barents Sea. They have traditionally  
16 been a pipeline supplier to Europe. They have now  
17 become interested in diversifying both into LNG  
18 and into moving into the eastern markets such as  
19 China. And so the question of how that policy  
20 develops will affect the amount of LNG that is  
21 available.

22 This sort of is a map of the major  
23 export basins of the former Soviet Union. Nadym  
24 Pur Taz up here in Western Siberia is essentially  
25 the workhorse of Europe, of the European supply.

1 Russian exports to Europe, to continental Europe,  
2 amount to about 25 to 30 percent of the total and  
3 Nadym Pur Taz is where the bulk of them come from.

4 It has the world's second and third  
5 largest gas fields but they are now in decline.  
6 They brought a new gas field on line recently.  
7 There's still a lot of gas there. It's only the  
8 decline is the equivalent of two billion feet a  
9 day per year. That's roughly the equivalent of  
10 LNG exports out of Algeria.

11 The issue that people have been looking  
12 at is will the Russians be willing to expand based  
13 on Nadym Pur Taz. There is gas there. Or do they  
14 want to move to some of the other gas that they've  
15 got which is the Yamal Peninsula or offshore  
16 Barents Sea in Shtokman. That would enable them  
17 to diversify their supply sources. There are very  
18 large reserves there.

19 The Russians have made enemies,  
20 unfortunately their biggest customers in Europe,  
21 partly because of the political problems with  
22 Ukraine interrupting supply, the fact that they  
23 refused to open their -- to create open access to  
24 let independent producers compete for markets in  
25 Europe.

1                   And as Europe has been tending to move  
2                   to LNG as a diversification option, when the US  
3                   got interested in LNG, it began to look as if the  
4                   -- to the Russians as if the Russians had a  
5                   diversification option in LNG to the United States  
6                   out of Shtokman. They originally were talking  
7                   about moving the Yamal Peninsula down into the  
8                   continent, then they got interested in Shtokman.  
9                   Now Shtokman is 300 miles offshore Murmansk under  
10                  shifting ice so it is a technological problem as  
11                  well as a political problem.

12                  More recently they seem to have backed  
13                  off that. They have backed off cooperation with  
14                  the companies, they have backed off interest in  
15                  LNG and it's not clear which way they go. But if  
16                  they decide to go the comfort way to pipelines  
17                  that will affect LNG supply and will affect the  
18                  way in which the relationships between the  
19                  Europeans and the Russians proceed.

20                  The other interesting question of course  
21                  is that when you go to international meetings and  
22                  see Russian presentations they envision some sort  
23                  of a pipeline system that runs from Sakhalin  
24                  through Irkutsk up to Western Siberia that will  
25                  feed Asian markets. Now Irkutsk is the big gas

1 field that is expected to come into China.

2 Difficult negotiations between the two countries.

3 If Sakhalin is linked and they decide to  
4 go the pipeline route out of that link that will  
5 affect the amount of LNG that is available out of  
6 Sakhalin. So that is not, clearly not a question  
7 obviously resolved as yet.

8 You might have seen in the press that  
9 the problems that existed for Shell in Sakhalin  
10 are now beginning to surface with BP in Irkutsk.  
11 Suggesting what worries a lot of people, that the  
12 Russian policy is to take control of all its gas  
13 and its gas exports and eliminate the role of the  
14 companies in trying to decide where the stuff  
15 goes.

16 The Middle East will be the dominant  
17 incremental supplier in the Pacific Basin between  
18 now and 2020. But 61 percent of the Middle East's  
19 uncommitted gas is in a single gas field shared by  
20 Qatar and Iran, the north field in Qatar, the  
21 south part is in Iran.

22 And if one includes the additional  
23 uncommitted gas in Iran, those two countries  
24 account for nearly 90 percent of the uncommitted  
25 gas in the entire Middle East.

1           Qatar has declared a moratorium on  
2 further LNG expansion beyond 2012 and Iran is  
3 under international sanctions.

4           Qatar's caution plus Iran's geopolitical  
5 constraints thus make it difficult to project the  
6 quantities and timing of additional Middle East  
7 supplies beyond 2012. Everybody expects it to be  
8 important but it is very hard to figure out how  
9 you schedule it given these questions.

10           Okay, the demand projections. While  
11 Northeast Asia once dominated LNG trade it is  
12 being surpassed by the Atlantic Basin.

13           Construction underway will provide a  
14 bulge in supply. And I think because the market  
15 is undersupplied that will be met by a bulge in  
16 demand and so my reduced growth rates take place  
17 after 2012.

18           By 2020 OECD Europe in the Atlantic  
19 Basin will provide the largest regional market,  
20 although if you combine the Atlantic and Pacific  
21 North America it is somewhat larger.

22           And Europe provides a very strong market  
23 in the high case, but in the low case if there is  
24 less LNG the assumption is that you are able to  
25 depend much more on pipeline supply. Northeast

1 Asia is pipeline dependant for interregional  
2 trade, North America is LNG -- I'm sorry, let me  
3 say that again. Both Northeast Asia and North  
4 America are LNG dependant for international/  
5 interregional trade. Europe has the pipeline  
6 option. So you would expect in the low case to  
7 see much more pipeline supply and much less LNG.

8 And here are simply the base case  
9 projections showing Pacific Basin, Atlantic Basin.  
10 And I include the Indian Subcontinent really in  
11 this Middle East sphere of influence.

12 Supply projections: With Qatar leading  
13 the way, Middle East supply will grow rapidly  
14 between now and 2010. Thereafter growth will be  
15 more modest. Australia is growing rapidly in the  
16 Pacific Basin, Southeast Asia is not.

17 The Atlantic Basin will benefit from  
18 major additions in North and West Africa,  
19 particularly in Nigeria. Soon Iran in the Middle  
20 East and Russia in the Atlantic Basin will become  
21 important exporters during the latter part of the  
22 forecast. And here is the supply projection. And  
23 as you can see the shifting of balance between the  
24 various regions.

25 In conclusion, in all three studies,

1 scenarios in the study, LNG demand will experience  
2 high rates of growth.

3 There are substantial uncertainties in  
4 the way in which demand will develop and will be  
5 supplied.

6 The way in which world gas demand  
7 responds to a high energy price/high cost  
8 environment will be an important determinant of  
9 how much LNG will be needed.

10 And the rate at which supply will be  
11 made available will depend in large measure on how  
12 suppliers deal with the technical, economic and  
13 geopolitical uncertainties in some of the future  
14 supply options.

15 MR. TAVARES: Are there any questions,  
16 Commissioners? Any questions from the public?

17 COMMISSIONER BYRON: Yes, Ruben.

18 MR. TAVARES: Okay.

19 COMMISSIONER BYRON: There was a great  
20 deal of information. Would you give that  
21 presentation again, please.

22 (Laughter).

23 COMMISSIONER BYRON: I saw the longer  
24 version as well, it was very good. Just a couple  
25 of questions that are related, at least I'm going

1 to relate them. The first is, and maybe you  
2 covered this. But with regard to liquefaction or  
3 the sending and the receiving terminals. Is there  
4 an imbalance there at this time, or as you say in  
5 the booked projects, we do have a shortage of  
6 liquefaction right now?

7 MR. JENSEN: Yes, we do have.

8 Essentially it's a tight market. There is not  
9 enough liquefaction capacity to meet demand, that  
10 has been the case. That may be softening. And in  
11 fact the sort of common view on the street is that  
12 the market is tight and will stay tight forever.  
13 My calculations say that this surge of supply that  
14 is coming on in 2009 and 2010 may in fact create  
15 quite a surplus during that period.

16 Now when you look at capacity for  
17 regasification terminals, that's a very complex  
18 issue. The reason is that capacities are stated  
19 by people in different ways. In a regasification  
20 terminal the gasifier is fairly cheap as a part of  
21 the terminals and it is very easy to over-size it  
22 if you have an intermittent demand. You can use  
23 it for peaking but the capacity of the storage  
24 tanks and the capacity of the pier to handle  
25 tankers may limit how much of that capacity you

1 could use over the year.

2 So people talk in terms of peak capacity  
3 and people talk in terms of annual or sustainable  
4 capacity. And the trouble is everybody's  
5 international figures add apples and oranges, they  
6 add both. If you look at Japan, their peaking  
7 capacity -- they report on a peak basis and they  
8 have 30 percent capacity factor. They buy on a 90  
9 percent take or pay contract so obviously their  
10 annual view is at 90 percent. So it is very hard  
11 to say whether, what the capacity relationship is  
12 in receipt terms.

13 COMMISSIONER BYRON: Thank you. Given  
14 the demand by region projections that you show and  
15 the increasing Pacific demand, and I'm not sure if  
16 you re able to answer this. But if we only look  
17 at the supply and demand situation throughout the  
18 world that you have indicated would it make sense  
19 for us to look at a different model for the way we  
20 develop LNG receiving in the Pacific Region of the  
21 US? For North America I should say. For  
22 instance, would it make sense for utilities to  
23 perhaps get in the business of procuring long-term  
24 contracts of LNG and perhaps even building LNG  
25 terminals?

1                   MR. JENSEN: The Pacific market is a  
2                   totally different market contractually than the  
3                   Atlantic Basin market. The Atlantic Basin market  
4                   with the UK on one side and North America on the  
5                   other side, gas-to-gas competition, contracts have  
6                   totally changed, the battle line between the  
7                   European oil link contract pricing runs down  
8                   through the North Sea. How that will be resolved  
9                   will take place in time.

10                   The Pacific, the Pacific Basin is still  
11                   very much a long-term contract, fairly inflexible  
12                   system and will be very slow to change. To the  
13                   extent that you're part of the Pacific Basin  
14                   supply it suggests that it may be in your interest  
15                   to be somewhat more conservative than the market  
16                   enthusiasts would suggest, if you know what I  
17                   mean. Because it may make much more sense to have  
18                   long-term contracts.

19                   At the same time arbitrage in the  
20                   Pacific will be a much more difficult issue  
21                   because in the Atlantic you have got supply on  
22                   both of the Atlantic, you've got markets on both  
23                   sides of the Atlantic. In the Pacific you do not  
24                   have an American Pacific supply to arbitrage. And  
25                   if you're shipping LNG from Indonesia to Japan and

1 all of a sudden an option to make a spot cargo  
2 develops to ship one to North America, it takes  
3 three times the tanker capacity to ship the same  
4 amount of stuff. So it is not a very good  
5 arbitrage market.

6 I don't know that that's answered your  
7 question but I think long-term contracts will be  
8 more important for you than they might be for  
9 somebody in the east.

10 COMMISSIONER BYRON: Thank you,  
11 Mr. Jensen.

12 MR. JENSEN: And if they're utility-  
13 oriented that's -- a utility may be better able to  
14 write one than a merchant.

15 COMMISSIONER BYRON: Okay, thank you.

16 PRESIDING MEMBER PFANNENSTIEL: I have a  
17 question about your projections of worldwide  
18 demand. You show the demand in China growing, and  
19 in fact growing considerably over what it is but  
20 it still ends up being a fairly small increment in  
21 worldwide demand. Is that because of the coal in  
22 China and your assumption is that China will meet  
23 its economic growth largely on a coal basis rather  
24 than on a natural gas or LNG basis?

25 MR. JENSEN: It's a very interesting

1 feature that if you look at the national demands  
2 in places like China or India, they anticipate  
3 much higher LNG or gas utilization, and by  
4 implication LNG, than do the EIA or the IEA.  
5 Those international groups are much more  
6 skeptical. And I have to say I belong to the  
7 skeptical camp because the assumption is that  
8 people who haven't been in the business don't  
9 understand how complicated it is to do it and  
10 that's where the skepticism comes from.

11 I had an interesting experience earlier  
12 this week because Stanford has been running a big  
13 project jointly with the Chinese and the Indians  
14 and they had a readout in Palo Alto of some joint  
15 study work and so I attended that. It was very  
16 interesting because listening to the Chinese and  
17 the Indians talk, I came away concluding that  
18 skepticism was well in order. One of the Indian  
19 men from the planning commission said, well if LNG  
20 gets down to \$4.50 it will take off. And I looked  
21 at that and I said, good luck, you know. And I  
22 think that's kind of the --

23 PRESIDING MEMBER PFANNENSTIEL: So the  
24 skepticism is not based on the fact that the  
25 Chinese will limit coal in any fundamental way.

1 It is much more on the political dynamics or even  
2 the institutional dynamics of trying to commit  
3 that much capital to China.

4 MR. JENSEN: Interestingly enough there  
5 have been at least four recent pricing mechanisms  
6 going on in Asia. The traditional one which went  
7 on for a long time was very inflexible and very  
8 stable. The Chinese broke the mold in the late,  
9 what, about five years ago with the Guan Dong  
10 contract with the Northwest Shelf and the Fujian  
11 contract with BP in Tangou.

12 At that point you had three people eager  
13 to put LNG into the market. You had the Northwest  
14 Shelf wanting to expand, you had Tangou and  
15 Sakhalin II wanting starter contracts, and  
16 everybody saw glitters of growing Chinese demand  
17 in their eyes and they cut the prices. And there  
18 was a real drop off in price.

19 At that point the Chinese were looking  
20 at a sharply cheaper LNG supply relative to coal.  
21 And it is still overpriced relative to coal, And  
22 they started getting enthusiastic. Now of course,  
23 all prices have gone through the roof so that  
24 dynamic has changed.

25 And I must say I think until they decide

1       that they want to limit carbon, and there is no  
2       evidence that they are there yet, it seems to me  
3       LNG, conservatism about LNG supply demand in China  
4       and India is warranted.

5               PRESIDING MEMBER PFANNENSTIEL: That  
6       actually was my next question. In your  
7       projections are you assuming kind of a status quo  
8       in terms of carbon? Internationally you're not  
9       really assuming that either the US or China or  
10      India or anybody else makes a major commitment to  
11      restricting carbon and therefore looking for some  
12      non-coal basis?

13             MR. JENSEN: Yes, I don't think I've  
14      assumed any dramatic change in policy evolution.

15             PRESIDING MEMBER PFANNENSTIEL: Thank  
16      you. Other questions from the dais? Susan.

17             ADVISOR BROWN: I wish -- Mr. Jensen,  
18      thank you for your presentation, that was  
19      exceptional and very instructive. Would you  
20      comment on global natural gas extraction drilling  
21      activity and how that factored into your supply  
22      forecast.

23             MR. JENSEN: Basically the gas business  
24      is on a net back basis, it is not on a cost of  
25      service basis. Net back basis simply says that

1       however you have determined what market prices are  
2       the sellers look to the market for the price and  
3       deduct the costs of regasification, tanker  
4       transportation and liquefaction to get a net back  
5       at the wellhead. And what happens is they decide  
6       whether the economics of investment are plus or  
7       minus.

8                   And I do not look at costs at the  
9       wellhead. There are two big problems when you try  
10      to take it back to wellhead costs. The first  
11      problem is that most of the world's gas fields  
12      today that are used for LNG are rich in gas  
13      liquids, often gas condensate.

14                   In many of those cases, and that is true  
15      of the North Field and South Pars, the value of  
16      the liquids is so good that it would justify  
17      flaring the gas to produce the liquids without any  
18      question. And I always call that negative  
19      opportunity cost gas because nobody will let you  
20      flare it, you'd have to reinject it if you had no  
21      market for it. So the costs may be negative in  
22      effect, that's what I'm saying.

23                   The second problem is that we're in a  
24      world in which the tax take, the tax regime of the  
25      host government is negotiable and governments are

1 going to decide how much of that they are going to  
2 take themselves. And one of the interesting  
3 things, you assume when prices go up automatically  
4 what happens is that there is a bigger incentive  
5 to invest. There is a period of time when the  
6 governments decide they have been had and they  
7 want to renegotiate terms. I mean, that's what is  
8 going on in oil in Venezuela, it's going on in gas  
9 in Trinidad, the terms of trade change.

10 So you've got the tax take, which to the  
11 international industry is a real cost, although it  
12 is not a true economic cost, and you have got this  
13 problem of byproduct credits and liquids. So I  
14 stay away from looking at costs directly.

15 PRESIDING MEMBER PFANNENSTIEL: Other  
16 questions here? Questions from the public?

17 MR. HONG: To follow up on your --

18 PRESIDING MEMBER PFANNENSTIEL: Excuse  
19 me, if you have a question you need to go to the  
20 microphone and identify yourself. You need to  
21 come up to a dais.

22 MR. HONG: Hi, I'm Bevin Hong with  
23 TransCanada.

24 MR. JENSEN: Okay.

25 MR. HONG: To follow-up on your issue on

1 net backs and how a supplier looks at that. How  
2 would they look at the Western United States in  
3 that regards in your whole stack of potential  
4 places to supply natural gas or LNG?

5 MR. JENSEN: Well, I mean essentially to  
6 the extent that contracts are still being written  
7 what is going on worldwide is a transition or  
8 evolution of contract terms that hasn't really  
9 settled out totally.

10 In the US what seems to be happening is  
11 that for the Atlantic and Gulf Coasts you are  
12 beginning to escalate to Henry Hub but you're  
13 taking a percentage off of it. In other words  
14 you're essentially having a term that is based in  
15 some percent of Henry Hub so it's directly  
16 escalated. That implies that there is a basis  
17 differential relationship.

18 I don't know how the contracts have been  
19 written out here. I think it would be very  
20 difficult to do because you in theory want to  
21 escalate to what you thought the market was out  
22 here but obviously the basis differentials had  
23 been variable. I mean, they've gone from plus to  
24 substantially minus and they may go back to plus  
25 again. So how you write that contract I don't

1 know and I am not close enough to know what the  
2 people who are writing them have done, so.

3 PRESIDING MEMBER PFANNENSTIEL: Thank  
4 you. One more.

5 MR. COWDEN: Hi, Bob Cowden, PG&E.

6 I see that you have a large growth in  
7 Australia in supplies between 2010 and 2015 and I  
8 just wanted to get your take. Do you see that  
9 supply serving the US West Coast or is most of  
10 that supply staying on the Asian-Pacific market?

11 MR. JENSEN: Well I think what's really  
12 happening, of course, is that with the real  
13 problems in Indonesia there is a supply shortage  
14 out there. What's happened is that Arun, which is  
15 in Western Sumatra, it was the Mobil project,  
16 arguably the most profitable LNG project the world  
17 has ever seen or will ever see, is now running of  
18 out gas.

19 Its in Aceh province where there has  
20 been rebellion so the idea of trying to find  
21 another gas source to keep the plant alive is not  
22 on the table. The Indonesian government has been  
23 robbing gas that's supposed to go to the plant for  
24 fertilizer to try to keep the locals happy. So  
25 Arun, everybody assumes Arun will be shut down in

1 several years.

2 Bontang in eastern Kalimantan has a  
3 fair amount of gas but the trouble is the gas is  
4 owned by one group of people who are later comers.  
5 The earlier trains are running off gas and nobody  
6 has quite figured out how to put the surpluses  
7 offshore together with the stuff onshore. And at  
8 the same time Indonesia is taking Bontang gas for  
9 fertilizer.

10 The assumptions -- The Indonesians are  
11 basically saying, when their contracts come up for  
12 renegotiation, and they are very close to  
13 expiration because they were written a long time  
14 ago, they are not going to be renewed at the level  
15 that they were before. So what you are doing is  
16 you are creating a gap that Australia can readily  
17 fill as Indonesia drops out. I think that's the  
18 game that is being played.

19 Clearly if a West Coast market develops  
20 they would be interested in that as well but at  
21 the moment I think the game is much more trying to  
22 replace Indonesia and handle growth in the  
23 Pacific.

24 PRESIDING MEMBER PFANNENSTIEL: Thank  
25 you, Mr. Jensen. Excellent presentation.

1 MR. JENSEN: Okay.

2 MR. TAVARES: Any more questions for  
3 Mr. Jensen? Unfortunately he is going to leave  
4 before the workshop is over so if you have any  
5 questions this is the time. Go ahead, sir.

6 DR. ARTHUR: Dave Arthur, City of  
7 Redding. In your judgment is there more or less  
8 or about the same political risk associated with  
9 reliance on oil or reliance on LNG?

10 MR. JENSEN: They're different. One of  
11 the interesting things about LNG is that if a  
12 project gets done and there is a contract the  
13 experience with some big glaring exceptions, the  
14 Algerians back in the 1970s, those contracts get  
15 honored. I mean, it's a very interesting thing  
16 that Indonesia has made contract commitments and  
17 is still honoring them even though it is costing  
18 them money to buy spot cargoes in the market.

19 So there are clearly risks there but  
20 they're different kinds of risks than oil. I'm  
21 not sure I can say which one is more or less  
22 risky. You've got to go in with your eyes open.

23 MR. TAVARES: I saw another hand. Come  
24 up to the podium here.

25 MR. SCHILLER: Steve Schiller with the

1 University of California.

2           Following up on Chairman Pfannenstiel's  
3 question on China and coal. If I understood your  
4 answer correctly you were saying that you are not  
5 assuming that China would change how it does its  
6 power production. But should China decide to  
7 convert more to natural gas as a basis of post-  
8 Kyoto treaties, for example, could LNG be a major  
9 supply source for that? What would be the issues  
10 associated with China using more natural gas for  
11 power. Thank you.

12           MR. JENSEN: Well obviously if they, I  
13 mean clearly if China clamps down on carbon it  
14 will have a powerful effect on LNG, there is no  
15 question about that. But it will also have a  
16 powerful effect on the economic price. And I am  
17 not talking about politically controlled prices,  
18 which China plays a lot with, but the economic  
19 price of power.

20           You cannot generate -- I mean, gas in  
21 China is relatively expensive and coal is  
22 relatively cheap. If you move from coal to gas  
23 you have really jacked up the price, the economic  
24 price of power. So I assume there will be some  
25 sort of a demand/response to the growth of

1 generation. But clearly it will have an important  
2 increase in the demand for LNG.

3 COMMISSIONER BOYD: Mr. Jensen, to  
4 follow-up on that. I've been sitting here  
5 agreeing with your conservative view of the  
6 Chinese, having spent some time there in the past.  
7 Even though they like to brag that their form of  
8 government allows them to make instantaneous and  
9 quick decisions and move they struggle with  
10 infrastructure issues.

11 And in light of my feeling that that is  
12 a big problem with the Chinese and your last  
13 response about the ability to jump back and forth  
14 between coal and LNG, do you feel even if they  
15 made, strangely, a decision to crack down on  
16 carbon, which would send a signal that they want  
17 to move away from coal, that they could really  
18 respond very rapidly to accomplish that? I mean,  
19 they do wonderful things sometimes but sometimes  
20 they stumble all over themselves.

21 MR. JENSEN: I guess my observation of  
22 China is that it is an economy in transition from  
23 command and control to market. And in with its  
24 command and control hat on it can do things that  
25 are unbelievable. I mean, the Three Gorges Dam,

1 the pipeline, the West-East Pipeline that links  
2 the Tarim Basin in the west with Shanghai.

3 I have a little graph I show and down in  
4 the corner is a little scale showing the various  
5 Asian pipelines. It's a scale from New York to  
6 San Francisco and I say, we never built anything  
7 like that in the US. But the problem is, once you  
8 build it and you really are trying to sell it in a  
9 market economy they have trouble essentially  
10 selling it and moving it into the market.

11 On top of that there are some tensions  
12 that I don't completely understand between  
13 regional governments and the national government.  
14 And what the national government wants to do  
15 sometimes the regional governments do not obey.  
16 So it's a very complicated thing in order to  
17 change policy and see what the results were.

18 COMMISSIONER BOYD: Like many parts of  
19 the world there is still this tribalism that rises  
20 up in governments on occasion. Thank you.

21 MR. TAVARES: Any last questions? No  
22 takers?

23 Okay, next we have Mr. Dale Nesbitt. He  
24 is actually one of the developers of the North  
25 American Regional Model. He is going to make a

1 presentation on the key assumptions of the model  
2 that we used to develop the reference case. So  
3 Dale.

4 DR. NESBITT: I appreciate the  
5 opportunity to be here. We have just moved from  
6 PowerPoint to .pdf, sorry about that. I think it  
7 will work fine. If it doesn't we'll be, we'll be  
8 shifting around.

9 I do want to say, as usual Jim has made  
10 a great presentation. Articulated the issues  
11 quite nicely. A lot of the world dimensions that  
12 I had to say I won't have to say because I think  
13 Jim has covered those very well. I'll add my two  
14 bits worth in where appropriate and where  
15 important, particularly on West Coast and emerging  
16 West Coast markets for LNG and world contracts.

17 But my job today is to talk a little bit  
18 about the assumptions and the realities really of  
19 North American natural gas markets, world natural  
20 gas markets, North American power markets, North  
21 American tradeable emissions markets and how they  
22 have been incorporated into the set of assumptions  
23 that we have used to craft a reference case in the  
24 four scenarios that we have here.

25 It works pretty well. Here are the

1 topics. I want to talk just a little bit about  
2 North American natural gas supply. It's a  
3 critical issue. We have been talking about LNG.  
4 But even in the high LNG cases at least two-thirds  
5 of our supply is buried in the turf of North  
6 America. We have got to understand that and we  
7 have got to put forth some assumptions that are  
8 reasonable there.

9 I want to talk a little bit about LNG  
10 and world gas trade.

11 I want to talk a little bit, actually  
12 quite a bit about industrial demand for natural  
13 gas and power in North America and how we have  
14 represented that.

15 Talk a lot about emissions allowances,  
16 trade, the environment and the effects on natural  
17 gas and power. This is a very much under-  
18 appreciated and under-quantified phenomena. We'll  
19 tell you the assumptions that we have made here.

20 And then finally talk a bit about the  
21 fuel burn for power generation in North America.  
22 Where is that now and where is it going?

23 The North American gas supply. I know  
24 the Commissioners were very involved with the NPC  
25 at least in a review mode. The NPC, alas and a

1 lack, is still the most current assessment of the  
2 North American resource base that anybody has.

3           What they did in the circa 2002-2003  
4 time frame was they assessed each and every one of  
5 the 950 plays from the Chukchi Sea to the Burgos  
6 Basin. And they did that by saying, let's come up  
7 with a field, size and depth distribution. Let's  
8 look at the deposition in the ground and then  
9 let's superimpose an assessment of finding and  
10 development cost across the top of that to try to  
11 get our hands around some notion of what's down in  
12 the turf and how much does it cost to get it out  
13 and how fast can you get it out. And how much  
14 land access might you need to get it out.

15           It is very important to set that  
16 background because the set of assumptions that are  
17 used in the reference case are an update and an  
18 extension of that assessment.

19           It is very interesting. Many people in  
20 this business have said, well, you know, those  
21 numbers lead to low gas prices in everybody's  
22 model, including the EIA's, those assessments are  
23 too optimistic. Let's chat about why that's the  
24 case and what we have done to render those more  
25 realistic.

1           Those superseded assessments that were  
2           made, if you can believe it, in the early '90s.  
3           And those assessments were based on cost estimates  
4           from the late '90s and the early '00s. What was  
5           the price of oil in 1998? Eight bucks. What was  
6           the price of natural gas in 1998? About \$1.80.  
7           What were the costs, the production cost estimates  
8           then? They were low, much lower than today.

9           And I think Jim has articulated quite  
10          nicely that commodity prices are off the charts  
11          today. They are at unprecedentedly high levels.  
12          Steel historically is a nickel a pound, now it's  
13          15 cents a pound. I grew up in the copper  
14          business. I grew up in a copper mining town and I  
15          can remember when copper price was 50 cents. Do  
16          you know what it is today? Three bucks. All  
17          commodities including oil and gas are very high.

18          So the issue is, how does this impact  
19          F&D costs. We have made a set of assumptions to  
20          try to incorporate these institutionally higher  
21          commodity prices including but not limited to  
22          engineering services into these estimates.

23          Okay, I'll let you read that. Now the  
24          adjustments that we have made to these to craft  
25          the base case here. If you go back and look at

1 the NPC's assessment work -- And I would commend  
2 NPC. It's still on their website, www.npc.org.  
3 You can look at all 950 plays. You'll sleep very  
4 well if you take that 479 page report and start it  
5 about ten p.m., you'll be asleep by 10:15. But  
6 it's got very good estimates in it.

7 One of the things that those guys did,  
8 and being self-critical of their own work they  
9 said, we had too many big fields in there, which  
10 means we had too much low cost gas.

11 So what we have done to create this base  
12 case is to remove a number of the very large  
13 fields and insert those back as small fields. And  
14 I think the domestic industry realizes that the  
15 size of fields that we have been encountering and  
16 prospectively will encounter in the coming five,  
17 ten, fifteen years are tiny, very tiny by world  
18 standards. And certainly very tiny by historical  
19 standards.

20 And the way to think about F&D costs,  
21 finding and development costs, is you divide the  
22 \$10 million whole by however many Bcf are down in  
23 the ground. That gives you the incremental cost.  
24 So if that Bcf down in the ground drops your  
25 incremental domestic cost goes up pretty much pro

1 rata.

2 Okay. And particularly in being self-  
3 critical of their work they were very critical of  
4 their own work in the Midcontinent and in the  
5 Rocky Mountains so those have been adjusted.

6 There has been some substantial  
7 adjustments due to the pessimism that has been  
8 encountered in onshore and Texas and onshore  
9 Louisiana. The field size and depth distributions  
10 have been reduced.

11 The key finding of the NPC, and I think  
12 it is very believed and understood around the  
13 industry is, there are volumes here in North  
14 America but they are encapsulated in very much  
15 smaller fields than we thought. A six Bcf field  
16 used to be a dry hole, now it's a monster. We're  
17 down in the one to one-half Bcf per well level.  
18 Which means our finding and development costs not  
19 being \$1.80 anymore are more like \$4.80. So that  
20 has been incorporated into the base case.

21 We have assumed, and it is certainly  
22 subject to alternative assumptions, that all of  
23 the gas that we have assessed here is quote/  
24 unquote in play. Which means that ultimately,  
25 perhaps with some temporal lag, we are able get

1 access to the entire domestic resource base with  
2 two exceptions, offshore Atlantic and offshore  
3 California. And the assumption that has been made  
4 in the reference case is those will be permanently  
5 off-limits to exploration and production.

6 This is a fairly bullish assumption on  
7 the availability of domestic gas to market. The  
8 NPC itself said that perhaps 40 percent of the  
9 resource basin in the Rocky Mountains will  
10 ultimately be off limits to E&P. Certainly the  
11 experience we have seen in recent years suggests  
12 that that is not an unrealistic number.

13 But I would commend us to think that we  
14 would have to make an assumption to keep that off  
15 limits. That it would be off limits forever, not  
16 just a few years.

17 We didn't feel like that would be a good  
18 base case. We felt like it might be a good  
19 sensitivity case to start restricting availability  
20 of domestic tracts of land to E&P. So it's a  
21 fairly bullish assumption.

22 De facto what this base case assumes is  
23 that all of the domestic resource base is  
24 accessible when and if it is economically  
25 competitive. That's a fairly bullish assumption

1 embedded in the reference case and there's  
2 sensitivity cases to examine the what-ifs.

3 Questions about the domestic resource  
4 base assumptions that are in the reference case?

5 ASSOCIATE MEMBER GEESMAN: How did you,  
6 how did you determine how much to downscale your  
7 megafield assumptions?

8 DR. NESBITT: Well we're spending quite  
9 a bit of time working with people in the industry  
10 and looking at discovery sequences that happened  
11 in the previous few years. What we did was fairly  
12 simple. We took the very largest fields down to  
13 about two Tcf, which is considered a monster field  
14 now. We've chopped those into categories of  
15 smaller field sizes, which de facto raises their  
16 production costs. So it was judgmental based on  
17 our knowledge and experience in the industry.

18 The US Geologic Survey has not  
19 reassessed those basins, private industry has.  
20 We're party to some of those things. But the  
21 answer to your question is it's really judgmental.

22 ASSOCIATE MEMBER GEESMAN: Then is it  
23 your judgment that the earlier geological  
24 assumptions were wrong or that the earlier  
25 economic assumptions were wrong?

1 DR. NESBITT: Both. But the geologic  
2 assumptions. That's really a good question and  
3 right on point. The assumptions in the Anadarko  
4 Basin and the Rockies Basin is that the geologic  
5 assumptions were wrong. They just weren't --  
6 there just isn't statistically an 11 Tcf field in  
7 the deep Anadarko Basin.

8 And the information that has emerged  
9 there is we have shown a lot more seismics out  
10 there. We've looked in the ground more and we  
11 don't see the formations that we saw back from the  
12 1998 to 2002 time frame when the NPC work was  
13 done. Dittos for the Rockies. So the experience  
14 has not shown both seismically and E&P the  
15 existence of these large fields. So I would argue  
16 that that's a geological shortcoming or geological  
17 learning.

18 The other one though, the other half of  
19 our question is true too. That when we looked at  
20 the original assessments that were done by the NPC  
21 those were done in '03 and they were based on  
22 roughly five years of previous finding and  
23 development statistics.

24 By happenstance that was a fairly low  
25 but increasing point in time in E&P costs. It had

1 low steel prices, very low; low copper prices,  
2 very low. There was surfeit construction in  
3 F&D resources around the world. So the thought is  
4 that the economics were a bit optimistic across  
5 that period vis-...-vis the long term.

6 So the answer to your question is both.

7 ASSOCIATE MEMBER GEESMAN: So then when  
8 you assume a 100 percent accessibility of what gas  
9 you believe to be there, and your timing I believe  
10 was said was based on the economics.

11 DR. NESBITT: Yes.

12 ASSOCIATE MEMBER GEESMAN: Where is the  
13 larger vulnerability in that new assumption? Is  
14 it geologic or is it economic?

15 DR. NESBITT: Good question. I think --  
16 My own view is if you assume, let's take the  
17 simple assumption that the NPC articulated as an  
18 alternative that 40 percent of the gas in the  
19 Rocky Mountains is held on BLM land and may well  
20 never be accessed. I don't really care what the  
21 cost is. That's a volumetric, geologic issue.  
22 Now there may be natural gas in Yellowstone  
23 National Park but who cares.

24 So I would argue that's a volumetric  
25 issue. And it is the target, I think, for some --

1 I know the industry worries about that a lot, for  
2 some careful rethinking of scenarios that we might  
3 want to run. Because I think implicit in your  
4 remarks is, so what if we don't have that. So  
5 what if you're wrong, Dale, what does that do to  
6 the gas price? It drives it up. Forty percent of  
7 the volume gone, you get it drives it up. Was  
8 that the question?

9 ASSOCIATE MEMBER GEESMAN: It was.

10 DR. NESBITT: One other point about the  
11 domestic resource base. What sets the price of  
12 natural gas for the next 30 years? Is LNG ever  
13 going to be in for marginal? No. The price of  
14 natural gas in North America is set by bad rock in  
15 North America. So it really matters, that's why I  
16 put it number one. What is the marginal cost of  
17 exploration and production from the very terrible  
18 rock that comprises North America by world  
19 standards, the leading term.

20 LNG and world gas trade. One of the  
21 things that we did this time is we didn't want a  
22 stand alone North American model. NARG is not  
23 enough, NARG is gone. What you need is a fully  
24 interconnected model of each and every region of  
25 the world so that you don't have to guess in the

1 blue, and this is what we tried to do in this base  
2 case.

3 So what is the price and cost of LNG  
4 coming onshore at Baja California? So what is the  
5 price and cost at Bradwood Landing or Skipanon or  
6 Tansy Point or Woodside or Cabrillo? We don't  
7 want to guess, we want a model. And so in your  
8 base case we did that. And that blue, that blue  
9 curve is important. I am going to give you a few  
10 insights from that that complement, hopefully  
11 don't refute what Jim said but they may in a few  
12 cases.

13 What we have done is to explicitly  
14 calculate the cost and price of LNG at every  
15 existing and prospective landing point in the  
16 world so that we are not guessing, at least that  
17 is our objective, what the price is of LNG, net  
18 back if you will, landed at Costa Azul. Landed at  
19 Cabrillo, landed at Woodside, landed at Tansy, et  
20 cetera, et cetera. We want to know that.

21 We also want to know that in the Gulf of  
22 Mexico, because there is intercourse between the  
23 Gulf of Mexico and California, it's by  
24 displacement. Yes it is a vulcanized market to a  
25 degree but we have common resources that serve the

1 Chicago market. And if you displace West Coast  
2 gas out of the Chicago market what happens to West  
3 Coast gas? The price goes down, westerners  
4 benefit. You have to know it all.

5 The model we've used has been around for  
6 awhile. It takes the North American piece in red  
7 and it hooks it up to the world in very much the  
8 way that Jim said, okay.

9 A little bit on the data. You might ask  
10 me about data, you asked Jim about data. It is  
11 very, very important to look at the LNG sources  
12 around the world and ask the question, how much  
13 volume at what cost is out there in the world on  
14 or near the waterfronts of the world. And the  
15 answer is it is infinity minus a little bit.

16 What is the cost of it? It's zero plus  
17 epsilon, where epsilon is mighty small. Jim  
18 articulated it right. Most of that gas near the  
19 water is pumping condensate at \$60 a barrel oil.  
20 It makes so much money there's not enough  
21 pillowcases to stick it into. So the direct  
22 marginal cost of gas all over the Persian Gulf is  
23 negative. Jim is absolutely right.

24 The issue is the infrastructure. The  
25 liquefaction facility, the boats, the

1 regasification facilities that get it out.

2           So we have assessed every assessment  
3 unit in the world and they are in your model, you  
4 can go look at those. It was done in  
5 collaboration with the United States Geologic  
6 Survey. I would comment to you their World Energy  
7 Program is on their website. You can read about  
8 every single producing basin in the world and know  
9 how much gas, oil and liquids are in the ground.  
10 It's great reading.

11           The demand in every country in the world  
12 has been put into the base case. I assign a lot  
13 of credibility to the IEA. And in answer to your  
14 question about China and India, the IEA is very,  
15 very, in fact surprisingly bearish on India and  
16 China ever importing LNG. They don't want to  
17 spend the hard currency.

18           The one thing about China that people  
19 don't realize is their per capita GNP is very,  
20 very low because they have got a lot of capita.  
21 Capital is a short device over there and they are  
22 not going to spend capital on LNG if they can  
23 spend it on coal. This is the IEA's view. I  
24 happen to subscribe to that view.

25           ASSOCIATE MEMBER GEESMAN: What's the --

1 DR. NESBITT: Every pipeline, existing  
2 and prospective in the world and every LNG  
3 liquefaction train, existing and prospective in  
4 the world, is in your base case. You can look at  
5 those.

6 ASSOCIATE MEMBER GEESMAN: What is the  
7 vintage of the USGS assumptions?

8 DR. NESBITT: The World Energy Program?  
9 The original publication was 2000. And what they  
10 put together on their website is a four-CD set  
11 dated 2000. Every year they have a conference and  
12 they update. If you asked me the specific regions  
13 that they have updated I don't know, but they've  
14 updated a tenth of the world in each year. So  
15 they have updated a tenth of the world, if you  
16 will, in each of the subsequent seven years and  
17 added regions like the Nile River Delta. So it's  
18 ongoing.

19 ASSOCIATE MEMBER GEESMAN: So they have  
20 stayed more up to date than they have with the  
21 North American resources?

22 DR. NESBITT: Yes they have. That's a  
23 really good question. Their last North American  
24 Assessment was in 1995. Absolutely, absolutely a  
25 good question.

1           ASSOCIATE MEMBER GEESMAN: Do you feel  
2 that they are entitled to a greater presumption of  
3 reliability than they have been in North America?

4           DR. NESBITT: I do, yeah, if you've  
5 been. And you can get to their conference, it's  
6 held every October in Denver, and kind of listen  
7 and see what degree of currency they have. They  
8 have a huge amount of funding from government  
9 agencies that we don't talk about because those  
10 government agencies that we don't talk about want  
11 to know how these governments that we don't talk  
12 about are going to develop their gas, oil and  
13 liquids resources.

14           So the aroma, if you will, of the  
15 assessment is there is a lot more money being put  
16 into it. As you probably know the USGS is line-  
17 itemed in the Congressional budget and their  
18 domestic program, I know this is hard to believe,  
19 is the subject of politics on the hill. I know  
20 how hard that is to believe. So they get squeezed  
21 for funding on the domestic resource base.

22           COMMISSIONER BOYD: I join Commissioner  
23 Geesman in perhaps a little skepticism because I  
24 still can remember sitting here, maybe even in  
25 this chair in 2003, when we had kind of a world

1 oil/gas conference in this room and the USGS was  
2 so bullish on North American supplies. I mean,  
3 the world is not at all today as they described it  
4 to us.

5 DR. NESBITT: That's exactly right,  
6 Commissioner Boyd. I think what they would say to  
7 you and what I have observed, and I certainly  
8 don't speak for them, is that as they sat here in  
9 '03 they realized the most recent assessment they  
10 had to draw on was published in 1995 and was  
11 actually done in the five years previous to that.  
12 And I think if you brought Don Gautier in there  
13 he'd say yeah, we're 15 years old. I agree with  
14 you.

15 Okay, what do we get out of this model?  
16 Everybody please raise your right hand and repeat  
17 after me, LNG price is not coupled with oil price.  
18 It's not. I was in Egypt about three weeks ago,  
19 we were trying to negotiate an LNG deal. The  
20 minister of Egypt looked at me -- Well I'll tell  
21 you the story.

22 My client said, who is trying to get an  
23 LNG liquefaction deal with the Egyptians, he said,  
24 if the minister asks you a question about price,  
25 Dr. Nesbitt, don't answer. Just don't say a word

1 about price, we don't want to go there. We just  
2 want to make sure their LNG comes to Texas.

3 So I walked in the door and the minister  
4 looked at me and said, Dr. Nesbitt, how come the  
5 price in Zeebrugge is 3.50 and the price at Henry  
6 is 7.50? I looked over at my client and I said  
7 well. He said, answer him. It's because it's  
8 always going to be that way, that's why. It's  
9 because Jim had it right.

10 Europe is at the confluence of more gas  
11 than you can think about. That 85 percent of the  
12 world's gas that is on a line north from the  
13 Strait of Hormuz to the North Pole is near Europe,  
14 it is not near North America. And to get any of  
15 that gas the European price is going to be soft.

16 Another little fact about Europe, it's  
17 only about five-eighths to two-thirds as big as  
18 North America, Europe is not that big. They've  
19 got more folks than we do but they don't burn more  
20 gas than we do. So it is very important to think  
21 about that.

22 Now the other thing, \$3.50 and \$7.50.  
23 What is the price of oil in BTUs today? Ten. Now  
24 where I grew up \$3.50 is not equal to \$10 and  
25 \$7.50 is not equal to \$10. Maybe that reflects on

1 where I grew up but that is just -- the oil and  
2 gas prices are not coupled. They are not coupled.  
3 They may be correlated but they are not the same.  
4 They are not the same commodity, they don't have  
5 the same use. Very important.

6 The other thing about LNG contracts. He  
7 also asked me, the minister said, I heard kind of  
8 a funny story about the French. About two weeks  
9 ago, this was about three weeks ago, I heard what  
10 the French did is they took a delivery from the  
11 Algerians under contract. Put it in a cryogenic  
12 tank. As soon as the Algerian boat was over the  
13 horizon they put it on another boat and sold it in  
14 North America. They broke the contract. They  
15 didn't keep the gas, they sold it.

16 And if you go to a place like Poten &  
17 Partners today that rings a bell, they've got a  
18 big bell sitting on the trading floor. Every time  
19 a spot cargo trades they ring the bell, you can't  
20 even have a conference, the bell is ringing all  
21 the time. LNG is not following the contracts, LNG  
22 is following the market. Very, very interesting.  
23 Now I don't know what that means but certainly in  
24 the base case that we have done for the Commission  
25 we've assumed that LNG is fully arbitragable.

1 That's an aggressive assumption about price but  
2 that is what has been assumed.

3 One of the other insights that you have  
4 is that North America is the big dog. North  
5 America is 25 Tcf, Europe is only about 15. The  
6 price is going to be firm in North America. It  
7 will attract these cargoes, particularly on the  
8 East Coast. And I won't make more any remarks  
9 about that, I think Jim was quite right in his  
10 remarks there.

11 So we wanted to understand these and to  
12 interleave them on your considerations of North  
13 America. If you want to ask me any questions  
14 about that later I'm glad to field those.

15 Number three, industrial demand in the  
16 United States. Questions about LNG? Okay,  
17 Industrial demand in the United States. One of  
18 the big issues in industrial demand in the United  
19 States, if you have gone to the DOE hearings on  
20 the energy bill which I went to, two days long. A  
21 day and three quarters is the gas users  
22 complaining the price is too high and they're  
23 leaving North America. They don't want to hear  
24 substance. Just all the fertilizer manufacturers  
25 and everybody else. And it's absolutely right,

1 they can't live in a \$7.50 world.

2 So what happened was Dr. Ken Medlock of  
3 Rice during the NPC and later under the  
4 sponsorship of the CEC decided he would try to  
5 build a statistical model of demand that included  
6 lags, own price, that's gas price, oil price,  
7 income and the weather. He did that and he found  
8 out that the leading term in gas demand is gas  
9 price.

10 And then the Commission hired  
11 Dr. Medlock to build the demand functions for the  
12 model that you use and those are the models that  
13 are in there, the demand functions that are in  
14 there. They presage quite low industrial demand  
15 in North America by EIA standards, quite low.  
16 Because at the prices you're projecting, according  
17 to the historical record the gas demand in North  
18 America in the industrial sector simply won't be  
19 there. The industry simply won't be there.

20 And that's very important. Somebody  
21 will ask, why isn't the EIA publishing that? If  
22 you're the EIA every one of the 535 guys on the  
23 Hill comes down and says they want high gas demand  
24 in their region because they don't want to see  
25 projections of their region engaged in economic

1       disability or debilitation. And so your  
2       institutionally forced to put forth a high demand  
3       projection for industry.

4                You don't have that. You have what you  
5       hired Dr. Medlock to do, which was put together  
6       gas demand projections that are consistent with  
7       the historical record. And that's done in the  
8       WECC, it's not done in the rest of the country.  
9       So that's important. We'll go beyond that. You  
10      have a fairly modest here projection of industrial  
11      gas consumption. We're going to see where the  
12      high side here is in a minute.

13               Questions about industry? What's in  
14      your base case? Okay.

15               Environment/tradable emissions, blah,  
16      blah, blah. Very quickly. Good old days,  
17      electricity was an intensely local business. PG&E  
18      could do their own business, Edison could do their  
19      own business. They owned all their plants, they  
20      didn't have to talk to nobody about nothing, if  
21      you will. Not anymore. Because what we now have  
22      is we have for SOx we have a nationally traded  
23      emissions market which connects us up to Epsilon,  
24      it connects us up to AEP. So we have to bid for  
25      SOx credits nationwide.

1                   NOx, the NOx laws are about to change.  
2           We have the SIPCALL states that are seasonal only.  
3           In 2009, 2010 we're going to go to year-round.  
4           Everybody is going to have to elect their way.  
5           California has some grandfathering. But these  
6           laws are getting tough. Mercury is going to  
7           start. Mercury starts at 48 tons. It's going to  
8           15 tons very quickly. And under almost any of the  
9           bills we see on the Hill CO2 trading is going to  
10          start. McCain-Lieberman, Binghamon, Feinstein.  
11          Different caps, different trades.

12                   Now what that means is that power is not  
13          a local issue anymore. It also means if we look  
14          at all four of those things, SOx, NOx, Mercury and  
15          CO2, which fuel gets hit by each and every one of  
16          those? Coal. Coal. These things have already  
17          cut into the fat on coal and they're cutting into  
18          the meat now. So it's very important, okay.

19                   What we have put into your base case for  
20          natural gas burn outside the WECC -- inside the  
21          WECC I'll tell you what we did but outside the  
22          WECC is our integrated supply demand run in the  
23          power sector connected with these tradable  
24          emissions allowances so that we have a view of gas  
25          burn outside the WECC that is more consistent with

1 the way these traded emissions allowances in the  
2 environmental business are driving the system.

3 Now people will tell you, yeah, yeah,  
4 yeah, I get it, I get it. What that means is that  
5 nobody is going to build a new coal plant. That's  
6 right. But if we have tradable emissions  
7 allowances in carbon what else is going to happen?  
8 You ain't going to run the coal plants you got.  
9 It affects the operation of the system as well as  
10 the implementation of a new system.

11 And to give yourself one quick piece of  
12 evidence on that. Think what happened in Europe  
13 18 months ago. Are you aware of what happened in  
14 Europe when they were trading carbon? What  
15 happened? The carbon price got to what? Thirty  
16 bucks, 30 bucks a ton.

17 What was the leading thing that happened  
18 in Germany when that happened? The coal plants  
19 stopped running at time of base because that's the  
20 only way you can meet the cap. You can't afford  
21 emissions allowances for 8,760 hours a year.  
22 You're not going to roll them out at time of peak  
23 or you'll have a shortage but you'll roll them out  
24 at time of base.

25 What happens when you roll them out at

1 time of base? You used to burn coal and now you  
2 burn? Gas. It stimulated gas demand off the  
3 charts. So it's very interesting.

4 In the base case that we have crafted  
5 here for you we have run this model and we have  
6 put the gas burn outside the WECC from this model  
7 into it. Inside the WECC we have used the  
8 statistical studies that were done by the CEC  
9 staff and Dr. Medlock. So the reference case  
10 embeds the CEC power burn forecast within the WECC  
11 and these burns from this integrated model outside  
12 the WECC.

13 Okay, one of the really --

14 ASSOCIATE MEMBER GEESMAN: How  
15 consistent are the two?

16 DR. NESBITT: They're not.

17 ASSOCIATE MEMBER GEESMAN: It would seem  
18 there's a pretty large dichotomy there, isn't  
19 there?

20 DR. NESBITT: I don't think so. But I  
21 think it was very -- it's very important. I think  
22 what we should do, if I were the benevolent  
23 dictator I would in the electric sector, this is  
24 my personal view, use the integrated solution  
25 inside and outside the WECC. I would use the

1 Medlock demand functions for all sectors other  
2 than the electric sector. That's if I were the  
3 benevolent dictator.

4 But there is an inconsistency, I agree,  
5 Commissioner Geesman. I don't think it's a fatal  
6 inconsistency but you're aware of what you've got  
7 there.

8 Now here is an interesting little issue.  
9 If the Binghamon level cap in trade came in, the  
10 Binghamon level cap in trade comes in, everybody  
11 thinks that pretty tepid. And there were no  
12 safety valve. In other words the carbon price was  
13 going to float so that you'd hit the cap, how high  
14 would that carbon price get? How high would it  
15 have to get before we could hit the carbon cap?  
16 That's a darn good question, isn't it?

17 Our numbers suggest, everybody hang on  
18 to the arms of your chair, 50 bucks a ton. That's  
19 what it takes to hit even the Binghamon cap. It  
20 really stimulates the gas. This is not a trivial  
21 issue.

22 So this is the system that you use to  
23 generate the outside WECC portions of your base  
24 case.

25 Last slide. The gas burn outside the

1 WECC is pretty strong in these cases, in your base  
2 case, and it is because they're reflecting the  
3 SOx, NOx, mercury, and I'll call it the tepid or  
4 the fairly benign Binghamon safety valve on  
5 carbon, seven bucks a ton.

6 That's it. Questions, comments? How  
7 did I do on time?

8 PRESIDING MEMBER PFANNENSTIEL:  
9 Questions?

10 MR. TAVARES: I see one hand. Get close  
11 to the microphone and identify yourself.

12 MR. SWEENEY: Yes. My name is Mark  
13 Sweeney, I am a consultant working with the  
14 California Natural Gas Vehicle Coalition. Dale, I  
15 have a question about assumptions.

16 Before the workshop back in March a  
17 document was put out listing the inputs and  
18 assumptions for NARG and the first one listed was  
19 the alternate or substitute fuel price forecast,  
20 which is a forecast of crude oil prices.

21 And the document indicates that for the  
22 2005 natural gas assessment report the EIA high  
23 oil price case was used as a reference point on  
24 all prices for the natural gas price forecast. It  
25 also said that the plan was to use the high oil

1 price from the 2007 annual energy outlook in  
2 developing the natural gas price forecast in this  
3 effort.

4 The actual draft report though says that  
5 the reference case oil price was what was used in  
6 developing the forecast. So I want to clarify  
7 which oil price forecast was used in developing  
8 the model results. And then I have a follow-up  
9 question.

10 DR. NESBITT: It was the reference  
11 price. But I want to share one insight with you.  
12 And that is, are you ready for this, gas and oil  
13 really don't interact in North America anymore.  
14 You know why? No refiner produces heavy oil  
15 anymore. There is no linkage between gas and oil  
16 in North America. We used the reference.

17 MR. SWEENEY: I agree with that but I  
18 think you would agree that there is some impact on  
19 the natural gas price forecast as a function of  
20 the assumed crude oil price, however small that  
21 may be. I guess --

22 And just so everybody understands that  
23 the high oil price case that EIA has prepared and  
24 that the CEC uses calls for oil prices to go to  
25 \$100 a barrel in 2030. The reference case

1 forecast suggests that oil prices in constant  
2 dollars will go to \$60 in 2030, and that's a  
3 difference of \$40 a barrel.

4 And what I am trying to understand is,  
5 is there any reason why someone would assume that  
6 a more optimistic outlook on oil prices that was  
7 made two months ago was appropriate two months ago  
8 or two years ago, now? Is there any reason why  
9 one would have a more optimistic outlook for oil  
10 prices to the extent of \$40 a barrel in 2030?

11 DR. NESBITT: Is the question, let me  
12 reframe the question to make sure we get it. Are  
13 you suggesting that \$100 a barrel might be a more  
14 reasonable assumption and that by assuming \$60 it  
15 is more kind of optimistic or less realistic?

16 MR. SWEENEY: Well, it's a whole lot  
17 more optimistic and it's a whole lot more  
18 optimistic than the assumption that was described  
19 in March that you were going to use. And it is  
20 certainly a lot more optimistic than the  
21 assumption that was made two years ago.

22 MR. FORE: Well, we used the reference  
23 case.

24 MR. TAVARES: Identify yourself.

25 MR. FORE: I'm Jim Fore with the CEC.

1 We used the reference case forecast from the 2007  
2 annual energy outlook, really to match with the  
3 fields group into the oil. They were using that  
4 sort of as their base, they told us.

5 We did do sensitivities that used the  
6 higher oil price in order to see the impact that  
7 it would have in the gas market and they will be  
8 covered later this afternoon. That was one of the  
9 sensitivities we ran was to use a high oil price  
10 and a low oil price to see how it impacted gas.  
11 And so we will be covering that as part of this  
12 workshop. That is one of the things on the table.  
13 Is that the right oil price to put in or should we  
14 use a different one. But we went with the  
15 reference case from the EIA as our starting point.

16 MR. SWEENEY: A \$40 a barrel lower oil  
17 price forecast level than what was deemed to be an  
18 appropriate assumption two months ago?

19 MR. FORE: I don't think we committed  
20 completely to what we were going to use. We were  
21 just going to use the EIA forecast. We did the  
22 sensitivity to it and the sensitivity showed that  
23 it didn't make much change in the gas demand  
24 because it doesn't influence the industrial demand  
25 that much.

1           And part of the rationale on that is  
2           that we felt a lot of the industries that had,  
3           that used a lot of gas had moved out. And so even  
4           though you have the high oil price there is no  
5           industry to switch back to the gas because they  
6           have already left and went to areas where they  
7           could get cheaper gas, such as the fertilizer  
8           industry and heavy users of gas.

9           MR. SWEENEY: My real issue is whether  
10          or not the oil price forecast is realistic or most  
11          likely to have an predictive validity. Let me  
12          just say that the Commission has consistently  
13          relied in the past on the EIA's oil price forecast  
14          and those forecasts for a long period of time have  
15          vastly underestimated the actual level of oil  
16          prices.

17          And even in the high oil price case we  
18          went back and looked at the annual energy outlook  
19          forecast going back ten years and looked at the  
20          predicted crude oil price in 2005 from those  
21          forecasts. And basically the actual crude oil  
22          price in 2005 was almost double what it had been  
23          forecast in the high oil case.

24          So I'm just wondering why the Commission  
25          seems to have this commitment to going with a

1 reference case forecast when every evidence from  
2 the marketplace would support the credibility of  
3 the high oil price case. And that is just a  
4 comment.

5 MR. FORE: Well you know, I got laid off  
6 in the oil industry when they thought it was going  
7 to \$100 and it went down to \$20 so these forecasts  
8 do vary a lot and I'll admit that. So what we  
9 have chosen is one we think that is somewhat  
10 realistic. And it may be low or it may be high  
11 and then we run the sensitivities to see if it is  
12 something that we really need to look at.

13 And what we're finding is that the high  
14 oil price is not impacting our gas demand that  
15 greatly. So, you know, it's something that we  
16 look at but we don't feel it is a significant part  
17 in changing the forecast outlook and what we would  
18 forecast to be the gas demand.

19 MR. SWEENEY: Well one last comment on  
20 the oil price forecast. That at the May 8  
21 workshop on the transportation fuels price  
22 forecast the staff basically presented three  
23 forecasts, a reference case, a high case and a low  
24 price case without making any indication of what  
25 they thought was the most likely. And it would

1 appear from looking at what was presented that  
2 they think the low price forecast is equally  
3 likely to occur as a reference or the high oil  
4 price case.

5 And I think at some point the Commission  
6 has to make a policy judgment on the outlook for  
7 oil prices. To say it is going to be between \$30  
8 and \$100 is too broad a range to rely on in making  
9 the kind of policy judgments that the Commission  
10 needs to make, especially in the AB 1007  
11 proceeding. Thank you.

12 COMMISSIONER BOYD: A couple comments I  
13 would make. I think the dialogue we just heard  
14 just reinforces the statement that was made that  
15 we struggle as an agency to convince ourselves and  
16 to affirm the fact that gas prices and oil prices  
17 are truly not connected. And I think you have  
18 heard today that is becoming more and more true.

19 And I think it is a little strong to say  
20 that we are dedicated to the EIA and their  
21 forecasts. Commissioner Geesman and I and all the  
22 staff went through lots of agony in the 2005  
23 Integrated Energy Policy Report struggling with  
24 that premise and trying to decouple ourselves  
25 because of the fact that they were more wrong than

1 right.

2           And I think the purpose of public  
3 hearings and workshops and ranges is to hear the  
4 kind of input you provided, to kind of get some  
5 dialogue going on high, low and medium and to make  
6 decisions. And I think we made a quantum change  
7 in 2005 as a result of lots of public discussion  
8 like this and upped, upped the view that we took.  
9 Not that we were right but who was. But we're  
10 trying to move in that direction and I appreciate  
11 the comments you've made.

12           ASSOCIATE MEMBER GEESMAN: I also think  
13 that in terms of the policy recommendations that  
14 the state ends up making or embracing, you want to  
15 look across the range of forecasts and attempt to  
16 develop policies that are robust across that range  
17 and that have some feel for which case in being  
18 wrong presents the greatest level of risk to you.

19           I think you're searching for as risk-  
20 adverse a set of policies as you can economically  
21 justify. I think at least from the state's  
22 perspective you want to step back a bit from  
23 feeling that you need to have an accurate  
24 prediction of prices going forward.

25           Our history I think induces a pretty

1 high level of humility about the accuracy of our  
2 price predictions. At the same time I'm  
3 confident, and I think historically we have put  
4 together a bundle of policy recommendations that  
5 attempt to minimize risk if our forecasts are  
6 wrong. And more often than not I think that the  
7 risk of our forecast being too low probably  
8 creates quite a bit more risk to the state than  
9 the constituencies that we're supposed to pay  
10 attention to, than our forecast being too low.

11 DR. NESBITT: Along those lines I think  
12 that I agree with that. Let me commend to you  
13 this document if you haven't seen it. I think  
14 it's fairly new from the EIA, it's terrific. It's  
15 called Annual Energy Outlook Retrospective Review,  
16 Evaluation of Projections in Past Editions, 1982  
17 to 2006. Nobody can see this but blue means they  
18 were too low and green means they were too high.  
19 Everything is blue or green.

20 All the forecasts -- And it's not right,  
21 Mark. All the forecasts that were made before  
22 about 1998, the oil price was always lower. The  
23 federal government was always forecasting too high  
24 on oil price and the price was always below. The  
25 worm turned in about 1995. The oil price was

1 always higher. What does that tell you? It tells  
2 you the federal government always forecasts  
3 today's price. Because it is too hard politically  
4 for them to forecast changes in the system.

5 So what it tells you, and I am very  
6 cynical, I never calibrate to the EIA. I don't.  
7 And I think to the CEC's credit, you guys have  
8 done independent analysis here that just doesn't  
9 accept the EIA. The EIA is an intensely political  
10 body, intensely political body.

11 You have done independent work and you  
12 have taken the heat for it and I think that is  
13 very commendable, you know, in the interest of  
14 getting good, solid -- and I couldn't agree more,  
15 robust answers from the prospective of hedging  
16 rate payer and business risks for the people in  
17 the state, absolutely.

18 PRESIDING MEMBER PFANNENSTIEL: Go  
19 ahead. If you have a question go up to the  
20 podium.

21 MR. SWEENEY: I just have a follow-up  
22 comment. Dale, you know, I am not defending the  
23 EIA's forecast. I guess what I'm defending would  
24 be a more pessimistic outlook for the future level  
25 of oil prices than a more optimistic outlook.

1                   But basically the California Energy  
2                   Commission has relied entirely on the EIA's crude  
3                   oil price forecast going as far back as I can tell  
4                   for its forecast of crude oil prices and for its  
5                   forecast of petroleum product prices.

6                   And you look at a situation like AB 1007  
7                   where the policy objective is to reduce petroleum  
8                   dependance by displacing petroleum use with  
9                   alternate transportation fuels. Basically if you  
10                  adopt an unrealistically low forecast of gasoline  
11                  and diesel prices then you underestimate the  
12                  economic cost of continued dependance on petroleum  
13                  and you also underestimate the net benefits that  
14                  result from the displacement of petroleum by  
15                  alternate transportation fuels.

16                  And I agree with what Commissioner  
17                  Geesman said about it is important to be aware of  
18                  the range of possibilities because the uncertainty  
19                  is substantial. But ultimately I think people  
20                  have to make a judgment about what they think the  
21                  most likely outcome is recognizing that there is  
22                  lot of uncertainty around that.

23                  So from my vantage point simply  
24                  recognizing the uncertainty doesn't get you to the  
25                  point you need to go to, which is a point of

1       having, based on what we know, all the  
2       information, what is the most likely expected  
3       outcome, recognizing that that very likely will  
4       wrong. Thank you.

5                   PRESIDING MEMBER PFANNENSTIEL: Thank  
6       you. Another question?

7                   DR. ARTHUR: Dave Arthur, City of  
8       Redding. As I've listened to your presentation  
9       and the one previously it seems like a certain  
10      theme is emerging and that is that supply  
11      continues to turn out to be less than what we had  
12      previously anticipated for a variety of reasons  
13      and demand seems to be increasing above what we  
14      maybe thought it was going to be, again for a  
15      variety of reasons. Is that a correct assessment  
16      of what we have heard and do you see that  
17      continuing into the future?

18                  MR. TAVARES: We're going to have a  
19      discussion on supply and demand in the next few --  
20      actually in the morning we're going to have  
21      discussion on demand and then supply this  
22      afternoon. Also we're going to have additional  
23      discussion on the uncertainty of the different  
24      variables, including oil, that we have. But we  
25      will have an anticipated comment here from Catie

1 Elder, she is from RW Beck and Associates.

2 DR. ARTHUR: Then I have one other  
3 question if we're not going to address that. And  
4 that was that it was stated that the price of  
5 natural gas in Texas was in the neighborhood of  
6 \$7.50 and the price in Europe was in the  
7 neighborhood of \$3.50 I believe. Do you see that  
8 kind of spread persisting where the size of the  
9 spread exceeds the transportation cost of moving  
10 the fuel itself?

11 DR. NESBITT: I think I'm going to speak  
12 for Jim. I think we'd agree, yeah. I think one  
13 of the things that Jim stated quite accurately was  
14 the shortage of liquid fuel supply, liquefaction  
15 around the world. That shortage I believe is  
16 temporary but we can fight how long it is.

17 As long as there is a temporary shortage  
18 there's going to be people fighting over that  
19 supply and basis differentials will not  
20 necessarily equilibrate to interregional  
21 transportation costs, absolutely.

22 We saw that in the winter of '05-06  
23 where Europe had a 30 degree cold winter and we  
24 had a 100 degree warm winter. The cargoes were  
25 sucked into Europe. Last year the Japanese had a

1 high demand, there were supply problems in  
2 Indonesia and cargoes were sucked off the Atlantic  
3 Rim into Japan.

4 So I do, I don't know Jim if you'd  
5 agree, I do see continued what Jim called  
6 instability I think quite correctly in these world  
7 LNG markets where price differentials exceed  
8 transportation costs for some period of time.  
9 Would you agree with that, Jim?

10 MR. JENSEN (FROM THE AUDIENCE): Sure.

11 MR. TAVARES: Okay, Catie is going to  
12 make a comment.

13 MS. ELDER: Of course, behind a screen  
14 nobody can see me, I realize. I'll try to stand  
15 up taller. But for those of you, I'm batting  
16 cleanup at the end of the day.

17 And some of the questions that Mr.  
18 Sweeney in particular asked are addressed in the  
19 presentation that's labeled Alternatives to  
20 Consider Uncertainty Around Staff's NARG results.  
21 And there is some analysis in there about the  
22 links between, or the lack of links between gas  
23 and oil prices. So if you can hang on until the  
24 afternoon I promise there will be more  
25 entertainment.

1                   MR. TAVARES: Okay, thank you. Any more  
2 questions for Dale?

3                   ASSOCIATE MEMBER GEESMAN: Is the  
4 afternoon the more appropriate time to ask  
5 questions about particular infrastructure?

6                   MR. TAVARES: Yes.

7                   ASSOCIATE MEMBER GEESMAN: Okay. And is  
8 Dale still going to be around then?

9                   DR. NESBITT: I'll be here as long as  
10 you need me.

11                   ASSOCIATE MEMBER GEESMAN: Good.

12                   MR. TAVARES: Yes, he's chained to his  
13 chair right here. (Laughter) Thank you, Dale.

14                   Next we have Jim Fore. He's going to  
15 start our discussion on the results that we have  
16 on the reference case and he will address demand.  
17 Jim.

18                   MR. FORE: Thank you, good morning.

19                   In addressing demand I want to take kind  
20 of the first part of the presentation talking  
21 about how we put the demand forecast together and  
22 some of the main assumptions in it and not so much  
23 about the numbers that we get out at this  
24 particular time, since we want to determine if we  
25 have looked at the demand sector properly and

1 allow everyone to understand how we came about  
2 developing the forecast that we have.

3 Our demand sector is divided into the  
4 Core sector, which is really the Industrial (sic)  
5 and Commercial sector. And we use that basically  
6 because these are sectors in which people cannot  
7 switch fuels. The Core sector could include some  
8 of the industrial demand if they are not able to  
9 switch the fuels.

10 The Industrial sector is normally  
11 referred to as the non-core and this is people  
12 that have the ability to switch between oil and  
13 gas. Although it is getting less there's still  
14 people that have that ability. In the West we  
15 have it broken down between Chemical and Non-  
16 Chemical.

17 In the East we just have an Industrial  
18 sector, just one sector. And in the East we use  
19 just Core instead of breaking it out by  
20 Residential and Commercial.

21 We have certain sectors that have a big  
22 demand of gas that are outside of this. In  
23 California the natural gas used in the enhanced  
24 oil recovery is a major demand of gas and so we  
25 have that broken down separately. For Alberta the

1 Oil Sands project basically accounts for about  
2 half of their demand for gas in that province so  
3 we have it broken out separately.

4 And then the power gen we get from CEC's  
5 forecasts for the WECC area. And as Dale said, we  
6 used his model in order to get the electricity  
7 fuel burn in the East. Now this forecast comes  
8 from our work, this comes from Alberta, this comes  
9 from a combination of CEC and the Altos people.  
10 This comes, part of it, from the WECC.

11 So it's all based on some elasticity  
12 functions that were developed by Dr. Medlock that  
13 we actually talked about in the last EIA -- IEPR  
14 report. We used it then. We updated them with  
15 the latest part of the historical data,  
16 recalculated the demand and that's what goes into  
17 the model.

18 Let me indicate how we use this in the  
19 model. What we do is we take the last year of  
20 historical data and we take the parameters that we  
21 have determined to be key for the demand sectors.  
22 And we take that and we put it in.

23 Now this is the areas where we have the  
24 inelastic as I told you. We get this from  
25 California, we get this from our report. We get

1 this from the electricity people. This is a  
2 combination of looking at the oil production in  
3 the state and the amount of gas used. We get this  
4 from Alberta. This is the export of LNG to Japan.

5 This is fixed so we treat it as an  
6 inelastic because we don't see that expanding.  
7 Which is not to say that we don't consider price  
8 or things other than just these numbers but we do  
9 it through an process where may we go back and  
10 forth between these when we do our calculations.

11 In the elastic side we have the  
12 residential, the commercial, the industrial, and  
13 we have it broken down into the two sectors here.  
14 And then the power gen outside of the West we go  
15 back and forth between our gas forecast and we can  
16 go back into the NARG with the electric forecast  
17 from Altos. And go back and forth to do that in  
18 order to adjust it over time.

19 Okay, for the residential/commercial  
20 sector we found that gas price, gross domestic  
21 product, heating degree days, population, and we  
22 have a residual factor in this. We started out  
23 with what we call a shadow price. We use a gross  
24 domestic product of around three percent.

25 We have heating degrees days, that's

1 based on a 15 year average for each one of the  
2 states. For Canada we didn't have good data so we  
3 used the heating degree days for the states that  
4 border the provinces in Canada and put that in.  
5 We used a population forecast from the Census  
6 Bureau for the US and from Canada we used their  
7 forecast. For California we used the one from the  
8 Department of Finance. We then calculate a demand  
9 for these sectors by states and put them into the  
10 model over the forecast period.

11 We go through the same process for the  
12 industrial sector where we use the industrial  
13 production index, the natural gas price and the  
14 crude oil price, which is the EIA price in order  
15 to account for substitution, and there is a  
16 residual factor. And we put this as the original  
17 forecast into the model.

18 This is just an idea of the elasticity  
19 values that we had. We know that they are  
20 performing as you would expect on an economic  
21 point of view. The higher gas price reduces the  
22 demand for gas. Greater GDP increases the demand  
23 for gas. Greater industrial production would  
24 increase the demand for gas.

25 Heating degree days most critical in the

1 residential sector, not so much in the commercial  
2 sector. And then we have the population as a big  
3 driver in the residential area, whereas domestic  
4 production in the commercial sector.

5 ASSOCIATE MEMBER GEESMAN: Why is your  
6 industrial elasticity so low compared to say  
7 chemical?

8 MR. FORE: We think the reason here is  
9 the lag involved here. Industrial changing, when  
10 you have a change they are going to respond much  
11 slower because they're going to have a lot of  
12 stuff backlogged on order that can go ahead and be  
13 filled before it really comes through the system.  
14 So the industrial sector, we think, responds a  
15 little less to the price simply because of that.  
16 there is a longer lag time there.

17 ASSOCIATE MEMBER GEESMAN: What  
18 industries are we talking about?

19 MR. FORE: Well, we have, we have just  
20 taken an aggregate of them.

21 ASSOCIATE MEMBER GEESMAN: In California  
22 or is that a national number?

23 MR. FORE: This is a national.

24 ASSOCIATE MEMBER GEESMAN: Okay.

25 MR. FORE: This is not really based

1 specifically in each individual state.

2 All right. In the power gen side in the  
3 East using the Altos work where basically this is  
4 the parameters they have in there that they are  
5 considering in order to get their gas burn. When  
6 we look at the California side the electricity  
7 department has provided us with one. They're  
8 basically using average conditions for the  
9 forecasts we have in there now.

10 It has been updated from the last IEPR  
11 report but it is not the final gas demand that  
12 we'll put in there. When they get a final one  
13 done we'll put it in and rerun the model to get a  
14 new demand forecast.

15 ASSOCIATE MEMBER GEESMAN: You know, I  
16 think there might be some value if just as a  
17 sensitivity we also ran the same model that you  
18 used on the East to indicate what electric  
19 generator demand would be in the West.

20 MR. FORE: I think that probably would  
21 be appropriate.

22 ASSOCIATE MEMBER GEESMAN: I know  
23 there's a tendency to want to support the home  
24 team and all but I think if there is a serious  
25 difference in results the Commission ought to know

1 about that.

2 MR. FORE: Well I did a comparison of  
3 the EIA regional demands looking at the census  
4 regions specific, Mountain and stuff. We  
5 basically overlay the EIA in the West, there is  
6 not a great deal of difference. When we go to the  
7 East the gas burn we're showing is much higher in  
8 the South Atlantic and in the East North Central  
9 and the West North Central, which are heavy coal  
10 users. So that's where we have our big difference  
11 in terms of the amount of gas being used in power  
12 generation.

13 Okay, we take a look at the overall gas  
14 demand for the North American continent. That  
15 includes Canada, the Lower 48 and Mexico. In  
16 Mexico basically we use the NPC data, that goes in  
17 there. Canada and the US is using the factors we  
18 showed before.

19 We note that there's a trend difference  
20 at around 2012. This is basically related to the  
21 price. We have gas prices in our forecast, which  
22 will be covered later, declining in the early  
23 years and so we see a more rapid growth in gas  
24 demand. As the price starts to increase we see it  
25 leveling off and not growing quite as fast so you

1 see a varied distinction in the trend in our  
2 demand forecast.

3 The overall growth is not very high.  
4 we're looking at two percent for North America.  
5 The US accounts for about 83 percent of North  
6 American demand so it really is the one that sets  
7 the growth for the North American market.

8 When we look at the demand for Core,  
9 which is Commercial and Residential, the driver  
10 here is basically population. And we see an  
11 increase both in Canada of about one percent, the  
12 US 1.1. Mexico is higher and part of that is  
13 because they really have no infrastructure for gas  
14 right now. And we see that expanding somewhat and  
15 that's why we see a rapid growth. But it was so  
16 low to start with it doesn't even show on the  
17 chart so any increase makes a rather big jump on  
18 the thing.

19 When we look at industrial demand we  
20 have two factors working here. We see a growth  
21 early years and then it starts to taper off.  
22 Within the Industrial sector we have two things  
23 happening in the early years. We both have  
24 declining gas prices, which we would think would  
25 increase the industrial consumption. We also have

1 declining oil prices during that time from the  
2 forecast so they're kind of offsetting each other  
3 so we don't see a really rapid increase there.

4 In the later years as the gas price goes  
5 up the oil price in the EIA forecast doesn't  
6 really start taking off until after the forecast  
7 period and so that's why I think we see some  
8 damping of the demand out there. Also we see a  
9 falloff with the enhanced oil recovery in  
10 California because of lower oil production. The  
11 main growth is the Canadian Tar Sands and Mexico  
12 has some increase in the gas. But overall in the  
13 US we see basically flat demand. I mean, we call  
14 it a minus two percent but that's outside of the  
15 model's ability to predict.

16 This is a real growth area is the power  
17 generation in the US. in the West we show it as  
18 basically flat, it grows a little bit in Canada  
19 and in Mexico. But it is in the eastern part of  
20 the US is where we have the major demand  
21 increases. As I indicated it is basically in the  
22 East North Central and West Central and South  
23 Atlantic. New England doesn't really increase  
24 that much. Surprisingly Texas and the West South  
25 Central doesn't increase all that much. But they

1 are all higher but not as great as they were in  
2 those other three sectors.

3 If we look in the western US and Canada  
4 they're fairly flat. They grow a little slower  
5 than the rest of the US and basically that's  
6 because of the power gen. We don't have as much  
7 increase in gas burn in the West as we saw in the  
8 East and that's why we have a slower growth rate  
9 here in the West.

10 If we look at the Western US we can see  
11 when we break out California, Canada and the  
12 Western States without California, we can see that  
13 they all are increasing a little bit but there is  
14 no dramatic growth really that I can see in there.  
15 The Western States, it's a little higher out at  
16 the end. That is basically driven more by  
17 population. We have a big increase in population  
18 in the Arizona, Nevada -- California has a decent  
19 increase in population but it is still under two  
20 percent, where some of the Western states are  
21 growing at greater than two percent and that's  
22 where most of that growth is coming from.

23 I put in our population just so you can  
24 see an idea of what we really see. Arizona is a  
25 big growth area. California is not bad compared

1 to some of the other states but Arizona and Nevada  
2 are the bigger ones. The rest of them are really  
3 fairly decent. Wyoming is a low one and Montana.  
4 You don't see a lot of growth when we look at  
5 those individually.

6 And British Columbia, again, their  
7 growth in population is fairly modest and that's  
8 why we don't see a lot of growth in Western  
9 Canada.

10 When we look at the residential demand  
11 you can see the impact the population had. It's  
12 greatest impact is in both the California market  
13 and in the Western States. California is so big  
14 to start with, when you get about a one-and-a-half  
15 percent increase in growth it does translate to  
16 higher gas demand. Canada you notice stayed  
17 fairly flat during that time period.

18 In the commercial area, again we don't  
19 see a lot of growth. Canada is a little bit  
20 faster than the rest of them. The Western States  
21 and California are just about the same rate of  
22 growth. We found another thing that would  
23 indicate that we would expect a greater rate of  
24 growth or a decline because we did have about a  
25 three percent gross domestic product during that

1 time period. And the population may be the two  
2 factors to show that growth.

3 When we look at industrial demand we're  
4 seeing California declining slightly or basically  
5 staying flat. Western Canada's increase is  
6 basically on the Oil Sands. we see an increased  
7 production in there. We see more gas being  
8 consumed for that. In the West again it's  
9 basically flat. The Oil Sands is somewhat of an  
10 iffy statement in terms of how much it grows.  
11 There are talks about reducing the gas demand by  
12 using other technologies to extract the bitumen  
13 from the oil sands but it is something that we  
14 wouldn't see taking place in the next ten years.

15 Okay. When we look at power gen, this  
16 comes from the electricity office. We see Canada  
17 staying fairly flat in their forecast. The  
18 Western States, you see it going up and down and  
19 that basically I think has more to do with how  
20 they see the stuff being transmitted and new  
21 additions later on. But we see nothing that is  
22 really surprising in that area.

23 If we look at California we see it  
24 fairly flat. Demand power gen is the big area  
25 followed by the residential. But we see a fairly

1 flat demand all the way through for the state.

2 When we look at the regional ones, again  
3 the residential is basically population. The  
4 difference in growth you see between the different  
5 utilities, which basically are based on the growth  
6 in population we saw in their districts. And the  
7 ones that had the greater population growth are  
8 the ones that show the higher growth in our  
9 demand.

10 The same with commercial. Population  
11 was one of the factors in there. We're using the  
12 same domestic product and other factors, heating  
13 degree days and stuff, so that's not having an  
14 impact on the variation between the districts.

15 Industrial demand. The orange is the  
16 enhanced oil recovery gas. that's where we see  
17 the big decline over time with declining oil  
18 production that we expect in the heavy oils that  
19 are being produced in the state.

20 Looking at power gen. This basically is  
21 just a reflection of the gas generating capacity  
22 in the districts and what might come on in the way  
23 of new generating capacity. So that's what  
24 causing basically the changes that are occurring  
25 in the power gen sector.

1 Overall our conclusions: We see the US  
2 or North America growing about two percent. We  
3 see the West growing less. When we look at gas  
4 demand domestically the US is going to continue to  
5 dominate all the way through the forecast.

6 The fastest growth area is the electric  
7 power and 5.5 is the national average, it's around  
8 6.5 in the East and lower in the West. In  
9 California we say basically flat growth, .8.

10 Basically we're seeing increased use of  
11 renewables, which is reducing potential gas burn  
12 in the electric generation. Slower growth in new  
13 capacity being put on. The reduced gas demand for  
14 enhanced oil recovery. Basically flat growth in  
15 the industrial sector is one reason why we see  
16 such a flat level of growth in California.

17 Okay, any questions?

18 ASSOCIATE MEMBER GEESMAN: How did you  
19 determine your assumptions on gas demand for  
20 enhanced oil recovery? Was that driven more by  
21 the geology of California oil fields or --

22 MR. FORE: Well it's really more by just  
23 looking at the trend we're seeing in production  
24 falling off right now. We're seeing increased  
25 drilling but we're not really seeing an increase

1 in the oil production in the state. I don't --

2 You know, the field is very mature down  
3 there and so we don't expect any new fields to be  
4 found that would be of significant size. So  
5 that's basically what it is based on is just the  
6 declining trend in the oil production.

7 ASSOCIATE MEMBER GEESMAN: You didn't  
8 try to replicate the economics of --

9 MR. FORE: No.

10 ASSOCIATE MEMBER GEESMAN: -- oil prices  
11 or gas costs for EOR?

12 MR. FORE: No, we didn't do a ratio of  
13 that.

14 ASSOCIATE MEMBER GEESMAN: Okay.

15 MR. FORE: We just basically looked at  
16 the steam required and did a base off that.

17 ASSOCIATE MEMBER GEESMAN: Okay, thanks.

18 PRESIDING MEMBER PFANNENSTIEL: Yes,  
19 Susan.

20 ADVISOR BROWN: Excuse me, Jim, I had a  
21 question for you. In calculating the California-  
22 specific natural gas demand how did you account  
23 for the effect of state-approved efficiency  
24 programs?

25 MR. FORE: Well of course it comes from

1 the demand office and they have accounted for  
2 that. On the electricity side, the electricity  
3 office has accounted for the renewables of 20  
4 percent up to 2013. They put that in so that's  
5 one reason why we see a reduction in gas in the  
6 electricity side.

7 In the actual demand numbers from  
8 residential, commercial and stuff, that really is  
9 coming from the demand office but we have felt  
10 that the changes basically were due to population  
11 on that. I am not sure how they have accounted  
12 for the efficiency in their equipment in new  
13 appliances and stuff but basically they put that  
14 into their forecast when they do it.

15 ADVISOR BROWN: So someone else on the  
16 staff would have to answer that question.

17 MR. FORE: The demand office is the one  
18 that gives us those numbers for California that we  
19 put in.

20 ADVISOR JONES: Susan, I think from  
21 reading the report it indicated that efficiency  
22 programs that are committed through 2008 are  
23 included --

24 ADVISOR BROWN: But not beyond.

25 ADVISOR JONES: -- but I am not sure

1 after that.

2 ADVISOR BROWN: Okay, thank you very  
3 much.

4 MR. FORE: That's true on the  
5 electricity side I know for sure. On the demand  
6 forecast since it's what, it's an '05. I'm sure  
7 that anything that has come up since then is not  
8 in the forecast at this time.

9 COMMISSIONER BOYD: Jim, an observation  
10 more than a question or a comment. It's been  
11 interesting to read of late about the Alberta oil  
12 sands and the interaction. With the new interest  
13 in the low carbon fuel standard that is spreading  
14 around very rapidly in the states and now the  
15 provinces and the potential impact on the  
16 production of those oil sands, and thus there  
17 would be a ripple effect on the use of gas.

18 I know it's nothing you can forecast now  
19 but I found it interesting to read in the last  
20 week or more that since the carbon footprint of  
21 Alberta Tar Sands oil is presumed to be extremely  
22 high there is suddenly question being brought  
23 about whether they will be as popular as we  
24 thought they were up until perhaps this year. So  
25 it will be interesting to follow that. I know you

1 can't predict or project anything but just another  
2 ripple on the pond.

3 MR. FORE: But I looked at it the other  
4 day in the press, you know, and they're talking  
5 about running a line all the way to the Gulf Coast  
6 to take Oil Sands crude all the way down there.  
7 And they were talking about running a line over to  
8 the BC to ship it off to Japan. So, you know,  
9 it's sort of a flip of the coin as to which way  
10 you want to go.

11 But we didn't take into account, you  
12 know, they're talking about how they might reduce  
13 their gas demand with new technology. And we did  
14 not account for that because of the shortness of  
15 the forecast period.

16 PRESIDING MEMBER PFANNENSTIEL: Other  
17 questions from the dais? From the public?

18 MR. MYERS: Richard Myers with the  
19 California Public Utilities Commission. What  
20 accounts for the, it looks like a large increase  
21 in the California power generation demand for PG&E  
22 between 2009 and 2010?

23 MR. FORE: We'll turn and look at the  
24 electricity office and let them come up and  
25 address that because we have taken it straight

1 from their work.

2 MS. TANGHETTI: A lot of times you see  
3 the lumpiness -- Angela Tanghetti with the  
4 electricity analysis office. Many times you see  
5 lumpiness in the forecast as a way new generation  
6 comes on line and possibly other things as  
7 possibly nuclear power, nuclear refueling  
8 schedules and how those are put in the model. So  
9 you do see some kind of lumpiness in the forecast  
10 from year to year by region in California. Does  
11 that?

12 MR. MYERS: It does appear that there's  
13 about a 25 percent increase from one year to the  
14 next. Are you sure it's just the lumpiness?

15 MS. TANGHETTI: Of resources being  
16 added?

17 MR. MYERS: Whatever accounts for that  
18 demand, I'm not sure. Is it just resources or is  
19 it the lumpiness in the model?

20 MS. TANGHETTI: Exactly, I can't tell  
21 you exactly there but when we do see lumpiness it  
22 is basically new generation coming on line when we  
23 see increases in natural gas demand like that.

24 SPEAKER IN AUDIENCE: PG&E has about  
25 2,000 megawatts coming on.

1                   PRESIDING MEMBER PFANNENSTIEL: Excuse  
2 me, you better, you better go to the podium if you  
3 want to add to something.

4                   MS. TANGHETTI: There is, again, quite a  
5 bit of new generation coming on in the next few  
6 years regionally within California.

7                   DR. ARTHUR: I had a question as to how  
8 the projected growth rates compared to say the  
9 last five or ten years. Just so I get a sense of  
10 whether we're growing faster, about the same or  
11 slower in these categories. Can you just comment  
12 on that briefly.

13                  MR. FORE: Basically on the electric  
14 side we're going slower because we've had the big  
15 increase in generating capacity. On the  
16 residential/commercial, the industrial is  
17 definitely down because we have lost some of the  
18 gas being burned there. The residential and  
19 commercial, I'd say it's down slightly but not  
20 significantly. Basically it would be due to  
21 appliance standards and building standards  
22 changing over time has reduced it.

23                  I mean, if we look at the per capita  
24 consumption in California, it's went down greatly  
25 over the last say 20 years. And basically that is

1 the efficiency standards coming in and taking  
2 effect. How much they are going to play in the  
3 future? I mean, you know, how much can you  
4 insulate a home before you start not getting  
5 anything, you know, out of it, and the same with  
6 the building standards. But it has been coming  
7 down. I think it may be starting to flatten off  
8 somewhat but it's too early really to tell.

9 PRESIDING MEMBER PFANNENSTIEL: Other  
10 questions? Go ahead.

11 MR. COWDEN: Bob Cowden, PG&E. I guess  
12 I wanted to maybe respond a little bit. When we  
13 look at our gas demand forecast that we generate  
14 we see a higher growth rate than what is in the  
15 CEC assessment. In our forecast we don't quite  
16 see the stair step between 2009 and 2010, it's  
17 more of a steady growth 2008, 2009 through 2010.

18 And it is hard in these gas models to  
19 kind of dissect the one thing that may be causing  
20 that. You know, in our models relative prices in  
21 different regions of the WECC have a big effect on  
22 relative gas demand. So, you know, there could be  
23 something going on. I guess I'm curious why it  
24 looks like the SoCal gas demand is going down at  
25 the same time the PG&E demand goes down in their

1 forecast. I'm kind of wondering what is going on  
2 regionally between some of the dispatch of  
3 generation.

4 MS. TANGHETTI: Yes, you're correct,  
5 regional price differences in various years do  
6 affect those -- the lumpiness of the forecast as  
7 well. So yes, you see one area going up, one area  
8 going down, and it is sensitive to price.

9 Overall gas demand probably is going to  
10 stay the same but you are going to see shifts  
11 regionally in where the generation is coming from.

12 MR. TAVARES: By the way, we got last  
13 night some comments from SoCal Gas in San Diego.  
14 So if we have time to address those we will do it  
15 after the next presentation. This is in regards  
16 to our forecast and their forecast so hold on to  
17 that. Any more questions on demand? Go ahead.

18 MS. SCOTCHI: Jill Scotchi, PG&E. Like  
19 Bob said, we're not seeing the -- we're seeing a  
20 greater growth rate in electric power gas demand  
21 than 1.1 percent so I would support Commissioner  
22 Geesman's suggestion that maybe we run an  
23 integrated gas power model to get similar gas  
24 demand forecasts in the West so we have an apples  
25 to apples comparison.

1                   COMMISSIONER BYRON: I believe looking  
2                   at the report the PG&E annual change that we're  
3                   projecting, correct me if I'm wrong, looks to be  
4                   about two-and-a-half percent per annum. On page  
5                   22 of the report.

6                   MR. FORE: Yes, that's close to being  
7                   right.

8                   COMMISSIONER BYRON: Not one percent.

9                   MR. FORE: And we will, when we get a  
10                  new forecast we will be updating that so you will  
11                  see some changes in what we presented in terms of  
12                  the California gas demand and the power gen in the  
13                  WECC when we put in the new forecast.

14                  DR. ARTHUR: Just as a point of  
15                  clarification. This is Dave Arthur, City of  
16                  Redding again.

17                  If I understand the assumptions behind  
18                  those numbers it assumes, for example in the case  
19                  of renewables, that there is sufficient  
20                  transmission in order to deliver the renewable  
21                  energy to the load.

22                  And second, I presume that you do not  
23                  have any large scale cutback of coal-fired  
24                  generation as a result of cap and trade or other  
25                  kinds of things that would have to be supplemented

1 or replaced by natural gas fired generation; is  
2 that correct?

3 MR. FORE: They do have, the  
4 transmission is there to move the renewables that  
5 are in there to the load centers.

6 DR. ARTHUR: That will make some people  
7 very happy.

8 MR. FORE: I didn't see a big cutback in  
9 coal but it does allocate it depending on price.

10 MS. TANGHETTI: Coal generation, the  
11 existing coal generation basically stays as it is.  
12 The forecast of new coal coming on line for  
13 instance, it's probably two-thirds less than the  
14 forecast that we had in the previous IEPR as far  
15 as generic coal coming online throughout the WECC.  
16 So that does have an impact in our results.

17 MR. TAVARES: Okay, we're going to  
18 change topics and we're going to go to the gas  
19 price forecast. Bill Wood will make a  
20 presentation, And then, again, if we have time  
21 before lunch then we will address, we'll allow  
22 SoCal Gas to make some comments. Bill.

23 MR. WOOD: Thank you very much and good  
24 morning to all of you including the Commissioners,  
25 it is good to be here with you.

1           Normally the gas price presentation is  
2 given after demand and supply and infrastructure.  
3 But if you notice this little word right here,  
4 retired, that means that I have got commitments  
5 this afternoon which are taking me away so  
6 therefore my presentation is going to be out of  
7 order.

8           And normally my presentation, I would  
9 tie together everything that has already been  
10 said. So now it's going to be a little bit  
11 difficult to try together things that haven't been  
12 said yet. So bear with me as we go through this.

13           I am going to start with conclusions and  
14 then build on how those conclusions came about.  
15 First off we see that the natural gas prices at  
16 Henry Hub and prices run, decline as we see  
17 happening in the NYMEX and then rising again to  
18 around \$7. Catie Elder later on this afternoon  
19 will be showing the differences between our  
20 forecast and Henry Hub and also other forecasts.

21           Our analysis also indicates that there  
22 are more supply options available which increases  
23 gas-on-gas competition in the US.

24           We also have noted that the gas spreads  
25 between Henry Hub and several other hubs are

1 increasing. That then indicates that Henry Hub is  
2 escalating at a slower rate than say the locations  
3 here that are serving California like Malin or  
4 Topock.

5 And a number of the basis spreads that  
6 used to be negative, because of the growing  
7 differential between those hubs and Henry Hub, are  
8 becoming positive. Some remain negative but there  
9 are a number of them, including California, that  
10 do become positive.

11 And of course my final conclusion here  
12 that comes out of the analysis is that California  
13 used to enjoy a discount for natural gas at the  
14 border and in the future it looks in about three  
15 to four years we may actually be having to pay a  
16 premium for our natural gas at the border.

17 Now most of my talk is going to be  
18 centered around this graph. It looks a little bit  
19 busy, it has a lot of information on it. And  
20 really looking back I wish I had made overlays for  
21 this so that you could see what I'm talking about.  
22 But first, all of you that have your papers with  
23 you you're going to build your own overlay as we  
24 go through this.

25 So get out your pencil and in the 2006 a

1 line from the New Jersey-Southeast Penn, which  
2 supposed to represent Transco 6 gas flowing into  
3 New York, and bring it all the way down to the  
4 AECO price, right in \$1.70. Now let's go to the  
5 other end of the forecast and do the same thing  
6 again and write in \$1.00.

7 That represents the price differential  
8 between the selected hubs that are showing here.  
9 Basically that is telling us that there are more  
10 supply options available to customers which is  
11 reducing the regional differentials, reducing  
12 volatility, to the point that over the next 10 to  
13 15 years those differentials will collapse by  
14 about 70 cents in 2006 dollars. That's number  
15 one. Let's see, I've got to look at my notes  
16 here. Hang on a second, which one I want to do  
17 next. All right.

18 Next thing I would overlay, I would  
19 overlay this very dark blue line. That represents  
20 the Henry Hub price. That is how -- No, I want to  
21 use this. I can work with this very nicely and  
22 everybody can see what I'm talking about and I can  
23 move it handily. All right, this represents then  
24 the Henry Hub price.

25 Early on notice where Henry Hub is in

1 comparison to California prices here. It's high.  
2 It's higher. And the only one that is higher than  
3 Henry Hub is the New York price. When we get to  
4 the end of our forecasted period we see that  
5 Malin, New York and let's see, this is Topock, are  
6 all higher than Henry Hub. Only the gas coming  
7 from the Rockies is below or approximately equal  
8 to Henry Hub.

9 What this is telling us then, this is  
10 implying that the pipelines that are delivering  
11 gas from the Southwest and from Canada are flowing  
12 at lower capacity. And that will be, Leon will be  
13 showing you that this afternoon. Yes, that is the  
14 case. With regards to the Rocky Mountain  
15 pipelines, Kern River will be flowing at or near  
16 capacity for the forecasted period.

17 Now this is because of the impacts of  
18 LNG coming into California and the rest of the US.  
19 Now if LNG was not available these pipes here,  
20 meaning the pipes coming from Canada and also  
21 coming from the Southwest, would be flowing  
22 heavier. That would then indicate then that  
23 prices in California would be higher without the  
24 LNG than it is with the LNG.

25 Okay. Now the next thing I want you to

1 do is in this area right here draw a line. A  
2 horizontal line and write 12 percent. And then in  
3 this general area draw another horizontal line and  
4 write 40 percent. And in this outer area draw  
5 another line and write 50 percent.

6 Now what those represent then is the  
7 share of LNG flowing into the Gulf Coast during  
8 our forecasted period. Initially LNG is flowing  
9 at 12 percent. That's sustaining, it's not enough  
10 to bring down the Henry Hub price.

11 We see that it increases to around 40  
12 percent in this general area and you can see that  
13 Henry Hub has dropped considerably below most of  
14 the sources.

15 And by the time we get out here we're  
16 approaching over 50 percent of the supply coming  
17 out of the Gulf Coast is LNG. We see that all  
18 other sources, at least that I have indicated  
19 here, are higher than the Henry Hub.

20 There was another point I wanted to make  
21 on this. Okay, I don't remember what it was,  
22 we'll just have to go on.

23 ADVISOR JONES: Bill, I've got a  
24 question.

25 MR. WOOD: Yeah.

1                   ADVISOR JONES: What accounts for the up  
2 and downs in between years?

3                   MR. WOOD: You know, it used to be that  
4 everybody complained because our forecasts were  
5 real smooth. (Laughter) And they said, well that  
6 doesn't really represent what's happening in the  
7 market. Now we put, we show what the market is  
8 really doing based upon new supplies coming in and  
9 shifting in demand and that sort of thing and so  
10 we get the sawtooth look.

11                   Maybe what we should have done is  
12 normalized all of these so we get one nice, smooth  
13 curve here to representing all of them. But  
14 basically, Melissa, it's based upon how different  
15 supplies come into the market and how they  
16 interplay at the point of time when they come in.

17                   All right. That was the other thing I  
18 wanted to indicate. No, we'll do that on the next  
19 slide. All right, this is just kind of a summary  
20 of what I told you so I'm not going to go over  
21 this anymore. Let's go -- What happened to my  
22 other? That other slide didn't get in here.  
23 Okay, well let's go back. I'm going to go back to  
24 this one then.

25                   In this slide one of the interesting

1 things is when I'm talking about the Gulf Coast.  
2 The Gulf Coast continues to produce in the area of  
3 about 20 to 25 billion cubic feet a day. But the  
4 LNG add-on is about 3 billion cubic feet a day per  
5 year. So it ends up that by the end of the 20  
6 year period we're looking at three times ten, it  
7 would be 30 billion cubic feet of gas coming  
8 through here. And overall supply coming out of  
9 the Gulf Coast is in excess of 50 billion cubic  
10 feet a day with about half of it being production  
11 and half of it being LNG.

12 I had a graph that I thought was going  
13 to get in but apparently it didn't get -- I made a  
14 modification this morning. I was going to show  
15 the differential between the prices. The actual  
16 price differential between LNG landed in the Gulf  
17 Coast, production in the Gulf Coast and Henry Hub.  
18 What happens is that Henry Hub and Gulf Coast --  
19 Henry Hub and LNG prices are almost right on top  
20 of each other. So basically then it looks like  
21 the LNG prices are driving the Henry Hub price.  
22 The production price is 10 or 15 cents below both  
23 of those too.

24 Now this particular slide is a little  
25 bit busy but I only need you to have a look at one

1 piece of it, that's the historical and then the  
2 2006 piece. Now what I've done here is I have  
3 gone to Natural Gas Week who publishes annual  
4 average hub prices and determined what the  
5 differential were between these selected hubs and  
6 the Henry Hub and compared the historical prices  
7 versus the 2006 is what I want to look at.

8 If you look at SoCal, right on. If we  
9 look at Malin, right on. If we look at AECO  
10 there's a little bit of difference here. But if  
11 you look at 2007 and compare that to what was  
12 happening earlier on in the decade you'll see that  
13 it's fairly close to being the same. Now if we  
14 look at Kern/Opal they are not the same. There is  
15 some correlation here but at least they're both in  
16 the same relative ballpark and the same sign.

17 If we look here at New York we're, I  
18 would say we could check this one off as being  
19 correct. We have this outlier that occurs in 2005  
20 but all the rest of the years are fairly close and  
21 you can see that it's declining and we continue to  
22 decline. Chicago is probably, you could consider  
23 that a check also because if you look back in here  
24 we're talking about plus or minus ten percent.

25 Here we're talking about minus ten percent then

1 growing from there to positive.

2           So basically what the model is telling  
3 us then, we may not agree with the actual price  
4 forecast because it may be too high or too low  
5 depending upon others' perspective. But what it  
6 is telling us is that it is giving us the right  
7 perspective between the different regions  
8 throughout the US so that we see how the market is  
9 really operating. We may not have the right  
10 forecast but we have a forecast that is regionally  
11 telling us how the market is going to operate.

12           Let's see, what else. I had one other  
13 thing. One of the things I was thinking, rather  
14 than always just comparing a point forecast that  
15 we have with other forecasts it might be  
16 interesting if it is available to actually look  
17 and see what kind of differentials they have going  
18 within their different hub locations within those  
19 models. All right, this is a summary of what I  
20 just said.

21           All right. This is the only end use  
22 price forecast that I am putting in my  
23 presentation today. Mainly because the forecast  
24 that we're using is primarily used in the  
25 electricity analysis that the Commission does.

1 Again, these two lower lines represent deliveries  
2 off of Kern River and off of El Paso Transwestern  
3 directly to power generation.

4 You can see and you would presume that  
5 they are lower than what would be delivered to a  
6 gas utility, which is shown in the upper lines.  
7 And that of course is that those power plants  
8 don't have to pay for the distribution costs.

9 Now early on it's kind of interesting.  
10 We see early on that the PG&E price is lower than  
11 for SoCal and for San Diego. I have in here also  
12 Otay Mesa. I don't know when Otay Mesa comes on  
13 but we at least have a price forecast for them  
14 that's fairly close to what San Diego is.

15 But during this period of time is when  
16 Costa Azul comes in. During the 2009-2010 time  
17 frame we have Costa Azul coming in. SoCal Gas San  
18 Diego prices differential between PG&E become much  
19 closer.

20 And then when we look out here to around  
21 2012, 2013, in this general area look what's  
22 happening here to Otay Mesa and to San Diego  
23 prices. We actually see a disconnect for San  
24 Diego from what is occurring in San Diego --  
25 what's occurring in the SoCal system and PG&E.

1                    Basically what's happening here is that  
2                    our model is kicking in the second phase of Costa  
3                    Azul. So we're going from a Bcf a day to two-and-  
4                    a-half Bcf a day. One Bcf a day is actually being  
5                    delivered into San Diego and then through to SoCal  
6                    Gas. What is happening then is the gas is being  
7                    priced as if it was being in SoCal Gas so  
8                    therefore San Diego being in the middle pays a  
9                    little bit less.

10                    Now there is a problem with this and  
11                    we're going to have to correct in our forecast our  
12                    believe, we'll have to look first to see, but  
13                    currently there's only three to four hundred  
14                    million cubic feet a day of capacity to flow from  
15                    Mexico into San Diego and there is no capacity to  
16                    flow from San Diego to SoCal Gas.

17                    We'll have to look to see what kind of  
18                    costs are put in there. But if those are low  
19                    costs then this is going, this shape is going to  
20                    have to change because we're going to have to  
21                    change the model to either restrict the quantity  
22                    of gas that can come into San Diego or jack up  
23                    that price that is moving gas to SoCal Gas through  
24                    San Diego.

25                    After that occurs then you can see that

1 San Diego tends to act a little bit more like an  
2 interstate pipeline than it does as a utility in  
3 terms of what price that's available.

4 Now one other point I want to make out  
5 of this. I've only showed six, six price  
6 forecasts, EG price forecasts, that we do within  
7 our office that are supplied to the electricity  
8 office. Actually we do a total of 34 of these  
9 representing a lot of different areas and  
10 deliveries off of different pipelines. So each of  
11 those areas then will have an individual price  
12 that is representative of that area.

13 That then, given the basis of what is  
14 going on here, it makes some of those areas more  
15 competitive than other areas. So if you're  
16 building an EG plant of course you want to be  
17 along an interstate pipeline because it is going  
18 to be the cheapest but you don't know what the  
19 transmission line capability is going to be.

20 Angela in her work in the electricity  
21 office takes care of that. We provide her a price  
22 forecast, she gives us a -- based upon that she  
23 will run her model and gives us a demand forecast.  
24 We put that back into our model and we iterate  
25 until we're happy with what the end results are.

1                   Okay, here is a summation of what I  
2                   hopefully have said.

3                   And that's it. Any questions?

4                   PRESIDING MEMBER PFANNENSTIEL:

5                   Questions from the dais?

6                   Questions from the public?

7                   MR. BILLINGS: Kevin Billings with Kern  
8                   River Gas.

9                   Bill, on your forecast here you show,  
10                  this last slide that shows forecasted electric  
11                  generation natural gas prices. You show Otay Mesa  
12                  gas pricing there.

13                  MR. WOOD: Um-hmm.

14                  MR. BILLINGS: Where did you get those  
15                  numbers and what was the basis or the assumption  
16                  for that?

17                  MR. WOOD: Okay, within --

18                  MR. BILLINGS: Because I'm assuming, I'm  
19                  assuming an Otay Mesa pricing then reflects LNG  
20                  pricing.

21                  MR. WOOD: That is correct.

22                  MR. BILLINGS: Okay, where did that come  
23                  from?

24                  MR. WOOD: What happens at this point is  
25                  that Angela tells us when Otay Mesa comes on. I

1 don't remember exactly when it is or if it does  
2 come on. But there is, we do have a price that is  
3 associated with any demand that may be put there.  
4 And that comes out of, that comes out of our  
5 model. That comes out of the NARG model. But  
6 that price is, it basically represents a tailgate  
7 price coming out of Costa Azul plus the  
8 transportation component on TGN to get it to Otay  
9 Mesa. The same way as going to San Diego.

10 MR. BILLINGS: Maybe Dale would answer  
11 this, I don't know. It just seems to me when LNG  
12 is trading over in Asia for \$10, \$12 a BTU, I  
13 don't know why it would land over here for \$6.

14 MR. WOOD: Well, I just work with the  
15 numbers. (Laughter) Somebody else is going to  
16 have to talk about the assumptions behind them.

17 DR. NESBITT: Well first of all LNG will  
18 trade for \$12 a BTU when you're short of capacity.  
19 The assumption that's submitted is you're not  
20 short of capacity.

21 And what LNG does, including in Japan,  
22 is it takes the fair market value of gas in Japan,  
23 which the Japanese conveniently set to oil price  
24 so they can attract the cargoes because they don't  
25 have any storage. They have to bid it because

1 they need that gas real-time at time of peak. But  
2 when they don't need it, it falls to the next  
3 available source. And the next available source  
4 under this set of assumptions is this index price  
5 and that's what they get for it, netted back  
6 exactly as Jim said.

7 So it would be nice if you could sell it  
8 for \$12 everywhere, you can't. One other issue  
9 about Asia that was never mentioned. Japan is  
10 minuscule. Japan isn't even three Tcf total  
11 market. It's about two. It's about six Bcf a  
12 day. LNG is going to overtake that just in Gorgon  
13 in the Northwest Shelf of Australia fairly quickly  
14 under most peoples' assessments.

15 MR. WOOD: Thank you, Dale.

16 There was another hand.

17 DR. ARTHUR: Dave Arthur, City of  
18 Redding. Could you elaborate a bit more on the  
19 precipitous decline between 2006 and 2008.

20 MR. WOOD: Which figure are you on?

21 DR. ARTHUR: You can pick any one of  
22 those you want. It goes straight downhill on all  
23 of your price charts from 2006 to '08. And  
24 needless to say, the forward curve is not quite  
25 replicating that particular pictorial.

1                   MR. WOOD: Well if we had Catie's  
2 presentation here we could compare what's  
3 happening with our forecast with the prospective  
4 three year forecast is on the strip for NYMEX.  
5 Basically NYMEX will follow the same sort of  
6 pattern. But if I remember right it's about up  
7 here and comes down something like for the three  
8 years. So we are --

9                   We tried to make the model replicate  
10 what is happening within the industry now. So  
11 therefore we've tried to replicate what's  
12 happening with regards to NYMEX. Now these  
13 numbers are directly out of the NARG model. They  
14 have not been doctored to represent what is coming  
15 out of -- doctored to represent NYMEX prices. So  
16 again, the NYMEX figure, NYMEX really is coming  
17 done something like this. So it's not quite as  
18 low as our forecast is when you correct it and  
19 then put it into 2006 dollars.

20                  MR. FORE: Let me address some of that  
21 for you. One reason the price is falling, this is  
22 Jim Fore with the CEC, is the LNG that we have  
23 coming in. We put in a capacity and we estimated  
24 when the new capacity would come on up through  
25 2012 and then we let the model bring it in as it

1 would.

2           We don't put any restrictions on this on  
3 the first pass and so it probably may be  
4 overstating what would actually come in. But  
5 because it is bringing in so much that is what is  
6 driving the price down.

7           If we go in and put some restrictions on  
8 it we would see a different trend there. But on  
9 the first pass we didn't want to try and outguess  
10 the market so we said let's see how much LNG will  
11 come in if we just let it flow under economic  
12 conditions and go to the best market and get the  
13 best price. This is what we get.

14           Now we'll take a look at the volume of  
15 LNG that's coming in. If we think it's either too  
16 high or unsustainable based on what Jim Jensen has  
17 told you this morning we'll put some restrictions  
18 in the model and we'll see that price come back up  
19 a little bit. But right now it's just an  
20 unrestricted flow of LNG that's driving that down.

21           MR. COX: Rory Cox from Pacific  
22 Environment. Regarding the price moderating  
23 influence that you see of LNG and the Henry Hub.  
24 Wouldn't there be a completely different dynamic  
25 going on on the West Coast? And I'm thinking in

1 particular there's EIA estimates that show that  
2 the dollar amount to bring LNG ashore on the  
3 Pacific Coast is much higher than it is on the  
4 Henry Hub and it is a completely different  
5 dynamic. As Mr. Jensen covered this morning, the  
6 trading regime is different in the Pacific than it  
7 is in the Atlantic. So is that, can we be so sure  
8 that it is going to have such a predictable impact  
9 on prices?

10 MR. WOOD: Well I think Dale kind of  
11 covered that particular question earlier with  
12 regards to the size of the market here versus the  
13 size of the market elsewhere and whether there are  
14 constraints within that marketplace.

15 Basically what we're seeing, I think if  
16 I remember correctly, we're seeing about 2 Bcf a  
17 day, 2.5 Bcf a day being landed at Costa Azul in  
18 the outer years. Of which about 1,500 of that is  
19 -- let's see, there's 1,000 coming across to  
20 California at San Diego and there's about 300 to  
21 500 being consumed inside of Mexico. Which leaves  
22 another Bcf that's making it all the way up  
23 flowing backhull on the northern border pipeline  
24 to -- the Baja pipeline, I'm sorry.

25 Backhull on the North Baja pipeline to

1 Blythe where it can go anywhere and come into  
2 California either through Southern California's  
3 southern line. It can go up El Paso's 1903 up to  
4 Daggett. It can flow east into Arizona for  
5 consumption there. Or it can even by displacement  
6 end up heading east of the Mississippi. We just,  
7 the model has the molecules coming to Blythe and  
8 it's kind of difficult to say exactly where it's  
9 going after that. Dale.

10 DR. NESBITT: Dale Nesbitt. One  
11 elucidating comment on your previous chart where  
12 you talked Malin and Topock Basins going positive  
13 relative to Henry Hub. That's why in part you  
14 have a higher landed cost and therefore a higher  
15 price of LNG on the West Coast and that is going  
16 to materialize in your runs here in terms of the  
17 movement towards premium basis at Baja, Topock,  
18 Malin, Pacific Northwest, et cetera. So it was on  
19 your previous chart, I just wanted to point that  
20 out.

21 DR. ARTHUR: I would just like to make  
22 one market comment for the Commission as it  
23 relates to the LNG issue. We have been in the  
24 market buying from one of the primary participants  
25 in Costa Azul over the last three years.

1                   When Russia pulled the spigot the first  
2                   time interrupting the flows to Europe the mutli-  
3                   year impact on the price of their product was \$1  
4                   and that occurred in two weeks. As you take  
5                   Commissioner Geesman's view that it is better to  
6                   err on the side that does the least damage I would  
7                   keep Russian politics in mind.

8                   MR. BILLINGS: Kevin Billings, Kern  
9                   River. I would agree with your statement there.

10                   My question then is, Mr. Jensen this  
11                   morning came in and gave a rather skeptical view  
12                   of the certainty of LNG supplies. And now we come  
13                   in here and this model would seem to indicate that  
14                   it's very robust. That you're going to have one  
15                   to two Bcf of LNG available to California.

16                   Does the model take into consideration  
17                   some of these uncertainties and assess some value  
18                   to these uncertainties? Because we have very  
19                   diverging points and opinions here.

20                   MR. FORE: Well let me address that  
21                   again. At this point it doesn't. The movement of  
22                   LNG in the world is based on the world trade model  
23                   and it's based on economics. We have not put any  
24                   restrictions in in terms of how many liquefaction  
25                   plants might be built further out or

1 regasification.

2 Now if we look at the permitted plants  
3 for regasification in the US, we looked at that  
4 and we said, okay, we know what's under  
5 construction that we felt would come on. And then  
6 we let the model flow and determine the amount of  
7 LNG that would come in.

8 The total amount that comes in is  
9 extremely high but actually if you add it up the  
10 plants that have been permitted, not necessarily  
11 under construction, if they all were built that  
12 forecast would be true if they could be filled up.  
13 So, you know, we're optimistic. We think we're  
14 probably over optimistic.

15 But we'll have to go back and look at  
16 how we might restrict it. We might put in  
17 something in terms of the capacity, might drop out  
18 some of the regasification facilities. But on the  
19 first pass we didn't want to do that. We didn't  
20 want to second guess what we thought the world  
21 would be like. We wanted to see what it would be  
22 like based on the model outcome and then decide  
23 whether we believed that's the way the world would  
24 be.

25 And that's one of the reasons we do

1 scenarios is to change this outlook of the world  
2 and then come up with a new deal. So we are  
3 rather optimistic and it does drive the price  
4 down, as you see here in the West where we talk  
5 about the LNG coming in.

6 We also have another factor that  
7 influences the West and that is the Rockies  
8 Express Pipeline that is in there. That is taking  
9 gas out of the Rockies, moving it into the  
10 midcontinent all the way to New York, which will  
11 affect the amount of gas available to California  
12 and it will affect the price. So that's an impact  
13 that's in there that we haven't talked about yet.

14 We're also looking at Canada, you know,  
15 and we talked about the oil sands. A lot of the  
16 Canadian gas, if Canada changes their outlook on  
17 coal-fired generation in the East and converts to  
18 gas-fired, there will be a lot of gas moving in  
19 Canada to the East and not coming to the West.

20 So those are some of the things that we  
21 kind of have in there that we were taking a look  
22 at now to see if we're going to change it or not  
23 change it. That's why we want your comments. So  
24 we know if we need to be cautious in some areas if  
25 you have actual data that shows us we're wrong.

1 That's what we're looking for right now.

2 MR. TAVARES: Yes. And keep in mind  
3 that this are, again, the preliminary results of  
4 the run so we are accepting other comments. One  
5 last question here.

6 MR. MYERS: Richard Myers of the CPUC.  
7 Bill, with regard to one of you bullets  
8 where you say:

9 "SDG&E's service area is  
10 flooded with LNG competing for  
11 the SoCal Gas market. Being  
12 in between the two SDG&E  
13 receives a lower price than  
14 SoCal Gas."

15 I was wondering how you came to the conclusion  
16 that SDG&E would get a lower price than SoCal Gas.  
17 Are you assuming that there is a transportation  
18 cost?

19 MR. WOOD: Well yes, there would be a  
20 transportation cost associated with moving the gas  
21 from one area to the other.

22 MR. MYERS: Well, the CPUC has recently  
23 adopted system integration for the Southern  
24 California area and basically there would be a  
25 single transmission price for the Southern

1 California area.

2 MR. WOOD: Well it may very well be the  
3 way the model -- I have to look to see what the  
4 structure is. I've been away from this too long.  
5 But it may very well be that the EG demand centers  
6 that we have in San Diego have the option of  
7 either pulling from SoCal Gas through Rainbow  
8 Station or pulling gas from TGN.

9 SPEAKER IN THE AUDIENCE: TGN, it is  
10 that way.

11 MR. WOOD: And it is that way?

12 SPEAKER IN THE AUDIENCE: It is that  
13 way, yes.

14 MR. WOOD: So you have gas flowing into  
15 San Diego where the power plants have the option  
16 of either buying gas from SoCal Gas or through  
17 SoCal Gas, meaning Southwest Gas, or buying gas  
18 from LNG through TGN. They have both those  
19 options. So they're getting a supply mix.

20 And because it is being flooded with LNG  
21 they are not, they're getting the LNG price and  
22 not the Southwest price that SoCal Gas is seeing.  
23 They may have the same markups with regards to  
24 transportation components inside both utilities  
25 but the commodity price is going to be different.

1                   MR. TAVARES: Okay, we are done. One  
2 more question there.

3                   MR. PAK: Could I just ask a quick  
4 question?

5                   MR. TAVARES: Go ahead.

6                   MR. PAK: Al Pak for Sempra LNG.  
7 Mr. Fore just said something that was inconsistent  
8 with the report. And I think this is at page 41  
9 where it indicates that the preliminary runs of  
10 the model showing the effects of the operation of  
11 Rocky Mountain Express Pipeline indicated that  
12 whatever the effects of the pipeline were on the  
13 Cheyenne Hub prices there would be no effect on  
14 the prices at Opal, which serves California. I  
15 think Mr. Fore indicated just moments ago that  
16 that was not true and I just wanted to know which  
17 position the staff really was taking there.

18                   MR. WOOD: If we look at Opal. When  
19 Rocky Mountain Express comes in right here in '09.  
20 So it's coming in at '09. This is the  
21 differential between Opal and Henry Hub. There is  
22 a drop that occurs in 2010 and there is a -- but  
23 it looks like it may be just a continuation of --  
24 I don't see anything that's really dramatic that's  
25 showing here. Of course it's up to your

1 interpretation of what's dramatic here within  
2 these price spreads. Jim.

3 MR. FORE: Well, we do have the Rockies  
4 in there and it is taking gas out. The full  
5 impact, the Rockies are going to be competing with  
6 the LNG that's flooding into the Gulf Coast right  
7 now so the price is kind of being set more by the  
8 Henry Hub price and the LNG impacts on that.

9 But there is volume that is taken out of  
10 the Rocky Mountains area that will go east that  
11 originally would be in place and could come here  
12 and so there is some impact. The model, it has  
13 Henry Hub and Opal tied together. I mean,  
14 Cheyenne and Opal are tied.

15 MR. BRATHWAITE (FROM THE AUDIENCE):

16 Yes.

17 MR. FORE: And so it is showing some  
18 impact there.

19 MR. BRATHWAITE (FROM THE AUDIENCE):

20 Yes.

21 MR. FORE: But not a great deal I guess  
22 at this time.

23 MR. BRATHWAITE (FROM THE AUDIENCE): But  
24 if you look at the

25 COMMISSIONER BOYD: Leon, you've got to

1 get up.

2 MR. WOOD: You've got to come and --  
3 Come on, Leon.

4 MR. BRATHWAITE: I am Leon Brathwaite  
5 with the California Energy Commission. I am the  
6 guy who do all the modeling. Anyway, if you look  
7 at this graph which was constructed by Bill you  
8 will see that the basis really is not when it  
9 starts from 2006 going all the way down to 2017.  
10 Now the Rockies Express do come in around 2009.  
11 As a matter of fact it fills out and goes east.

12 So you see, you are seeing some effect,  
13 even though you could probably say it's a  
14 continuation of the trend. But you are seeing  
15 some effect of that pipeline coming in.

16 Now I guess there might some little  
17 inconsistency in terms of what the report said but  
18 maybe that's something we need to look at and make  
19 sure we correct it in the final. Catie, you  
20 wanted to say something.

21 MS. ELDER: I was just going to add one  
22 point which is, remember Dale pointed out and I am  
23 going to amplify later in the afternoon for those  
24 of you who are awake that long (laughter) that we  
25 have got full access to all of the resources, all

1 of the reserves in the Rockies, at least at this  
2 point, assumed in the model.

3 That's something we've put on the list  
4 of things that need to have a look taken at to see  
5 if that's really the best assumption that we can  
6 make. There's certainly some restrictions on  
7 drilling that come out of EPACT, for example.  
8 There is a ban on Montana front range drilling.  
9 There is talk of a new ban on Wyoming Rockies  
10 front range drilling. There are other areas.  
11 Powder River Basin has been impacted by some  
12 issues with drilling and dealing with the water  
13 that comes out of the coal-bed methane production.

14 So we think that one of the things  
15 that's one our list to sort of tickle the staff  
16 about is to say, you need to take a look at that  
17 Rockies total access assumption to see if that  
18 really makes sense.

19 Now the question will be, if we restrict  
20 that we can get access to in the Rockies in the  
21 model will we then still see virtually no  
22 difference between the Cheyenne Hub price and the  
23 Opal price? That's what we don't know until we do  
24 that run.

25 PRESIDING MEMBER PFANNENSTIEL: I think

1 that we are about to close the morning session.

2 Ruben, do you have anything further for  
3 this morning?

4 MR. TAVARES: No, I just wanted to  
5 mention that we received the Southern California  
6 Gas comments before midnight last night and they  
7 wanted to make some comments. But we can start  
8 the afternoon with their comments if you prefer.

9 PRESIDING MEMBER PFANNENSTIEL: I think  
10 that's a good idea.

11 MR. TAVARES: Okay.

12 PRESIDING MEMBER PFANNENSTIEL: We'll  
13 break now until 1:30 and then reconvene.

14 (Whereupon, the lunch recess  
15 was taken. Commissioners  
16 Pfannenstiel, Boyd and Byron  
17 did not return after the  
18 recess.)

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## 1 AFTERNOON SESSION

2 MR. TAVARES: To my knowledge we lost  
3 some of the Commissioners. Don't take it  
4 personally. It is not the topic, it is not the  
5 speakers this morning either, it's just that they  
6 had other commitments. But we've gained another  
7 advisor, Tim Tutt is here with us.

8 We're going to depart a little bit from  
9 the agenda. We have three more presentations  
10 officially. However, I mentioned before lunch we  
11 had some presentations from SoCal Gas, San Diego  
12 Gas & Electric, and they're going to make a short  
13 presentation if you don't mind.

14 We have with us Herbert Emmrich here to  
15 make a presentation. Herbert.

16 MR. EMMRICH: Thank you very much,  
17 Commissioner and Commission staff. I appreciate  
18 the opportunity to present the views of Southern  
19 California Gas Company and San Diego Gas &  
20 Electric at this proceeding. I am Herb Emmrich, I  
21 am the Gas Demand and Economic Analysis Manager of  
22 SoCal Gas and San Diego Gas & Electric. As two  
23 years ago we also reviewed the gas assessment and  
24 we do have some comments.

25 Generally I want to say that the staff

1 did an outstanding job in making this assessment.  
2 I especially like the fact that you have scenarios  
3 because of the uncertainty that we have in gas  
4 demand, gas supply and especially in prices.

5 But overall the report, just like two  
6 years ago, shows demand being higher than what we  
7 are forecasting in the California Gas Report. And  
8 this is mainly due to the fact that we take into  
9 account the ten year energy efficiency goals that  
10 are mandated by the CPUC and also fully  
11 incorporate all of the renewables projections in  
12 our forecast.

13 In the overall SoCal gas demand  
14 forecast, as you can see by this slide, the staff  
15 is about half a percent of an annual growth factor  
16 and we have a negative growth factor. So overall  
17 the staff's report is about one percent higher  
18 than our's, which is easily within the realm of  
19 reason I would think. But it is higher.

20 In the residential market, again, we are  
21 concentrating our energy efficiency efforts in the  
22 residential market, especially in the low income  
23 also. The staff forecast is about .6 percent  
24 annual growth rate higher than our forecast.

25 In the industrial market the staff

1 kindly pointed out a mistake that I made. The  
2 growth rate actually is 1.2 percent, not 6.5  
3 percent higher.

4 In the electric generation market, which  
5 is usually the most controversial, we show that  
6 the staff's forecast is one percent higher.

7 Going on to San Diego's forecast. I'm  
8 going the wrong way here, sorry. San Diego's  
9 forecast, the staff report is quite a bit higher,  
10 2.9 percent. Generally the staff has not  
11 adjusted, I believe, the downturn in growth in San  
12 Diego, especially in the housing market. It has  
13 slowed down quite a bit.

14 The residential market in San Diego is  
15 about .9 percent annual growth factor higher than  
16 our forecast. Again, it is the energy efficiency  
17 programs that we incorporated. The staff  
18 incorporates only through the three year program  
19 cycle but of course we have a mandate for the full  
20 ten years with the CPUC.

21 The commercial and industrial forecast,  
22 we show no growth in San Diego, especially if we  
23 have concentrated energy efficiency in the  
24 commercial and industrial market. And therefore  
25 we show that even there is customer growth the

1 overall gas demand growth will be zero.

2 The electric generation market, we do  
3 have a new power plant, Palomar power plant, and  
4 another one coming on, Calpine. But these plants  
5 are very efficient. The electricity that will be  
6 generated will be more than the old plants but  
7 they will use a lot less energy. The heat rate of  
8 the new plants is about 7,000 compared to the old  
9 plants that are being phased out, over 10,000.

10 This is the overall comparison, I won't  
11 bore you with that. As you can see across the  
12 board the staff report has a higher growth rate in  
13 all market segments. I compared it also with the  
14 a cold year and dry hydro scenario on the electric  
15 power side and it looks like the hydro assumptions  
16 may be slightly different than what we have. So  
17 the staff is being more conservative, which may be  
18 a good thing for planning purposes.

19 On gas supply issues. Things have not  
20 changed in the last couple of years. The Alaskan  
21 and Canadian gas is still far off, maybe 2012 to  
22 2014.

23 There are plenty of resources in the  
24 United States but pretty much all of them are off-  
25 line. I think Dale Nesbitt mentioned something

1       like that.

2                   LNG, shale gas, tight sands gas, coal-  
3       bed methane, even coal gasification and biogas are  
4       all cost effective at these prices but they're  
5       slow to come on line.

6                   And with LNG everybody, no matter what  
7       forecasts you look at on the demand side and on  
8       the supply side, to meet the gap between supply  
9       and demand you need LNG.

10                  Everybody is saying that but it seems  
11       like we can't get a terminal in California  
12       approved. So our parent company is building three  
13       terminals, one in Baja Mexico, you know about  
14       Costa Azul, and two in the Gulf Coast. As far as  
15       I know they are all on schedule and the Baja  
16       facility is supposed to be operating in 2008.

17                  I don't know what the Energy Commission  
18       can do to foster LNG coming into California. We  
19       are hoping that those supplies will be available  
20       to keep the price down. Without that prices are  
21       going to be much higher than we're projecting.

22                  Compared to the staff report we looked  
23       at what the EIA is projecting for LNG deliveries  
24       coming out of Baja and they tend to be quite a bit  
25       lower than what the staff is assuming. Of course

1 we have no history because these are pure  
2 projections. No gas has arrived yet. But once we  
3 have a few years of history we can probably see a  
4 little bit better on what the real forecast would  
5 be. This is fairly speculative at this time.

6 The facility of course is fairly large.  
7 I believe it is 1.3 Bcf so the potential is there  
8 if the LNG arrives to bring more to California.  
9 But since you have an interconnection with Baja  
10 Norte and North Baja Pipeline that gas could also  
11 go to Phoenix and not wind up in LA. Of course  
12 the interconnect at Otay Mesa with San Diego would  
13 be the first choice. That's the shortest  
14 transportation route.

15 Overall we expect prices to remain high  
16 throughout this forecast period, around \$7 in  
17 constant 2006 dollars.

18 We hope that the LNG will start showing  
19 up. And then in the longer term that Arctic gas  
20 from Canada and from Alaska will actually arrive.  
21 You know, it's always another five years out and  
22 now it looks like even that may be optimistic.

23 The segment of the market that is  
24 pushing the demand for natural gas, of course, is  
25 the electric power market since coal is not

1 favored anymore. If you wanted to generate all of  
2 the power with gas that is now generated with coal  
3 I don't know what the price would be. Maybe it  
4 would be up to equivalent to oil prices. It would  
5 be \$10 per million BTUs. But we're hoping that  
6 LNG will arrive and keep that price down.

7 Of course in the long term you also have  
8 other emerging technologies such as clean burning  
9 coal, coal gasification and renewables. And that  
10 should also limit the price increases somewhat.

11 This is our forecast based, compared to  
12 the CEC. Our forecast is based on the CPUC  
13 approved methodology, which is looking at futures  
14 prices and then taking the long-term forecast of  
15 PIRA, CERA, the CPUC and the CEC's forecast and  
16 blending them together. This is the curve that we  
17 see right now. Prices are significantly higher in  
18 the short-term but as you see in the long-term we  
19 all seem to agree.

20 High gas prices, you know, impact the  
21 gas-intensive industries in California. So it is  
22 in all of our best interest to make sure we have  
23 adequate gas supplies. The ones that are most  
24 affected: the food and beverage processors; paper  
25 producers; chemicals; stone, clay and glass; and

1 metals producers.

2 Just to give you a rough idea. If the  
3 price is 70 cents per therm versus 40 cents a  
4 therm that's about \$1.5 billion per year of  
5 additional cost to California consumers.

6 Thank you. If you have questions,  
7 please.

8 ASSOCIATE MEMBER GEESMAN: Herb, my  
9 principal question relates to your opinion of the  
10 assumption that they used in the NARG model about  
11 the ultimate availability of natural gas in North  
12 America. Their assumption was that all of the gas  
13 would be commercially available and subject to  
14 development on an economic calculated basis. I  
15 saw your comments referenced environmental  
16 concerns and constraints to development of  
17 resources in the US. What is your judgment about  
18 accuracy of their assumption?

19 MR. EMMRICH: There's a lot of resource  
20 out there but most of it is off limits to  
21 development. It's even off limits just to do  
22 seismic. Dale talked about all these large fields  
23 that were supposed to be there that aren't there.  
24 Maybe they are there but nobody can even find them  
25 or be allowed to do seismic to find them.

1           These are in national parks or in  
2 wildlife preserves or offshore. There's plenty of  
3 gas offshore California, offshore the East Coast  
4 and offshore of Florida but that's all off limits.  
5 So we are limiting ourselves to the availability  
6 of supplies domestically.

7           So if you are running a model I think  
8 you have to make some kind of assumption that at  
9 least in the near term, near to medium term, those  
10 resources will not be made available.

11           Maybe if the gas prices are \$10, you  
12 know, the politics change. But if you look at the  
13 resistance to bringing natural gas ashore in LNG  
14 form. Nobody wants any facilities anywhere. The  
15 two facilities here in California were voted down.  
16 And on the East Coast there's court fights and  
17 everything to stop LNG from coming in, you know.

18           We feel LNG is a very good product.  
19 It's the cleanest fuel around. Why would somebody  
20 be opposed to it? The only place it seems to be  
21 welcome is in the Gulf Coast who are more familiar  
22 with gas and oil. The infrastructure there is  
23 designed to receive it. And that's why our  
24 company, the affiliates are building two receiving  
25 terminals in the Gulf Coast. But it would be a

1 lot more cost effective if we had one here in  
2 California somewhere.

3 But, you know, I am not a politician,  
4 I'm just an economist.

5 ASSOCIATE MEMBER GEESMAN: When did you  
6 start your career at the gas company?

7 MR. EMMRICH: About 23 years ago.

8 ASSOCIATE MEMBER GEESMAN: And what was  
9 your opinion or what were you hearing about the  
10 prospects for Arctic gas then?

11 MR. EMMRICH: We were actually  
12 participants in the pre-built segment of gas  
13 pipelines into British Columbia. As you remember  
14 at that time there was a proposal to build a  
15 pipeline for a mere \$2 billion at that time. Now  
16 the estimates are up to \$20 billion to \$30 billion  
17 to build a pipeline.

18 But we were looking at that because we  
19 were afraid that we're going to run out of gas  
20 here in the Lower 48. So that situation hasn't  
21 changed. In the meantime LNG has stepped in. And  
22 at that time we also proposed to have an LNG  
23 terminal at Point Conception, if you remember  
24 that. And of course that was voted down by Native  
25 Americans.

1                   ASSOCIATE MEMBER GEESMAN:  Would  
2                   California's interests be better served if at  
3                   least the Alaska portion of that Arctic gas were  
4                   brought down here by LNG?

5                   MR. EMMRICH:  The problem with having  
6                   LNG come in from Alaska is that you have to, under  
7                   the current law, the way I understand the Jones  
8                   Act, you have to have US crews and US built ships.  
9                   That basically makes it uneconomic to do so.  
10                  That's why the LNG out of Alaska probably will be  
11                  exported to the Far East.  It doesn't make any  
12                  sense to me but again, you know, that's politics.

13                  ASSOCIATE MEMBER GEESMAN:  Thanks very  
14                  much.

15                  MR. EMMRICH:  Okay.  Thanks a lot.

16                  MR. TAVARES:  Any questions.  There's a  
17                  question here.

18                  MR. COWDEN:  Hi, Bob Cowden from PG&E.  
19                  First I just wanted to echo Herb's point about the  
20                  commercial/residential growth in the staff report.  
21                  We had found the same, similar kind of results  
22                  from our studies.  That the demand growth, we're  
23                  forecasting a lower demand growth rate for those  
24                  segments.

25                  ASSOCIATE MEMBER GEESMAN:  Did you think

1 the difference in your case is attributable to  
2 different assumptions about the efficiency  
3 programs?

4 MR. COWDEN: Yeah, I was going to say I  
5 think that's one of the main things. The other  
6 things I think are maybe in the way we deal with  
7 temperature adjusted load may be slightly  
8 different than what staff does. We don't look  
9 purely at household growth as the determinant of  
10 core gas demand.

11 And then kind of conversely, we have a  
12 higher EG forecast burn in PG&E service territory  
13 than does the staff report.

14 ASSOCIATE MEMBER GEESMAN: Significantly  
15 higher?

16 MR. COWDEN: Ours is about four percent  
17 over ten years, relative to the staff's 2.4  
18 percent. You know, absent looking at model inputs  
19 it's hard to diagnose what that difference is  
20 attributed to.

21 ASSOCIATE MEMBER GEESMAN: Yes.

22 MR. COWDEN: Probably electric loads,  
23 hydro availability over that time frame, that sort  
24 of thing.

25 ASSOCIATE MEMBER GEESMAN: I guess with

1       respect to the electric generating results. It  
2       might be well advised for the staff to try to get  
3       together with the two utilities to try and better  
4       isolate what causes the differences there.

5               MR. COWDEN: We'd welcome that, that  
6       would be great.

7               ASSOCIATE MEMBER GEESMAN: I think that  
8       would be helpful to us.

9               MR. COWDEN: Okay, we'll work on that.

10              And the question I had for Herb was  
11       related to the EG demand. I think the SoCal Gas  
12       EG demand drops off around 2010, 2011 and I was  
13       wondering if your forecast had a similar profile  
14       than the staff's?

15              MR. EMMRICH: Yes we did have a decline  
16       because the new power plants being more efficient  
17       will generate more electricity but use less gas as  
18       the old plants are phased out.

19              MR. COWDEN: Okay. And I think ours is  
20       increasing because we have some new megawatts that  
21       are showing up at about the same time.

22              MR. EMMRICH: But I think overall the  
23       staff's forecast is reasonable. Because we don't  
24       have control over who builds power plants where.  
25       The utility can build power plants so we know

1 those plants will be coming on line. But a lot of  
2 plants are being served off of interstate  
3 pipelines and you could have that situation. We  
4 really don't know what those plans are.

5 ASSOCIATE MEMBER GEESMAN: Of course as  
6 a lot of these new plants come on line the older  
7 ones retire and you do pick up a heat rate  
8 improvement that we need to make certain is  
9 accurately reflected in our forecasts.

10 MR. EMMRICH: Right.

11 MR. COX: Hi, Rory Cox from Pacific  
12 Environment. Can you discuss Sempra's current  
13 negotiations with international LNG suppliers?

14 MR. EMMRICH: You know, that's an  
15 affiliate and I don't deal with that but I believe  
16 somebody from the affiliates is here. Al Pak was  
17 here. I don't know if he's still here.

18 ASSOCIATE MEMBER GEESMAN: No, Al is  
19 still here. He's sitting in the front row  
20 smiling.

21 MR. EMMRICH: Because we don't handle  
22 that at all.

23 MR. COX: Okay.

24 ADVISOR TUTT: Herb, I do have one  
25 question that relates again to the differences

1 between the staff and your forecasts. There are  
2 some differences even significant in 2006 numbers,  
3 the starting points. That can't be the energy  
4 efficiency assumptions, is that something else?

5 MR. EMMRICH: Well, I don't know where  
6 the staff gets their actual numbers from but our  
7 actual numbers are the actual numbers and they  
8 don't change for us. These are the filed numbers  
9 with the CPUC.

10 MR. FORE: Let me add to that. Our  
11 forecast is the one used in the '05 IEPR, which  
12 means it was done in '04. And so '06 is actually  
13 a forecast, not an actual number in ours. So when  
14 they come out with a new demand forecast that will  
15 change somewhat.

16 ASSOCIATE MEMBER GEESMAN: And the  
17 difference in the start points were an issue  
18 between the staff and San Diego in the electric  
19 side in 2005 so I think there may be a carryover  
20 of some of those methodological differences that  
21 we need to iron out for 2007.

22 MR. EMMRICH: We're just in the process  
23 of updating the Cal Gas Report for actuals for the  
24 year 2006. And that of course is made available  
25 to everybody so everybody should have the same

1 starting point.

2 ASSOCIATE MEMBER GEESMAN: Great.

3 MR. EMMRICH: There are some  
4 differences, though, on utility served load versus  
5 non-utility served load that the staff may be  
6 using some slightly different numbers. But those  
7 can all be adjusted.

8 ASSOCIATE MEMBER GEESMAN: Yes. And  
9 we've got some time in this cycle to try and iron  
10 out those differences.

11 MR. SCHILLER: Steve Schiller with the  
12 University of California. My question is probably  
13 more of a process question than it might be for  
14 the Commissioner or the staff. And that's, as I  
15 have been watching this morning there seems to be  
16 a focus with the IEPR work to show a point  
17 prediction per year of supply, demand and pricing.

18 And I guess probably all of us could  
19 agree whatever is predicted for 2017 will be the  
20 wrong exact number. And I could see value in  
21 having specific projections, that's the official  
22 California estimate for specific price at a  
23 specific point in time.

24 But it would seem that what would be  
25 also very valuable would be those same graphs

1 showing the uncertainty associated with that as  
2 would be typically shown with modeling results and  
3 a discussion of what the influences are as to what  
4 drives that uncertainty high or low and the  
5 implications for public policy. Whether it's what  
6 is happening in the Rocky Mountains or the LNG or  
7 pipeline production or efficiency programs, et  
8 cetera that's showing how that can affect  
9 different prices.

10 And so I guess my question is, is the  
11 purpose of the IEPR to come up with the price? You  
12 know, PG&E will pay \$7.92 in 2017 for power, gas.  
13 Or is it to show that uncertainty and what  
14 influences it?

15 ASSOCIATE MEMBER GEESMAN: The latter.  
16 But I think much of the discussion that you may be  
17 referring to probably is based more on what  
18 assumptions are going to go into the reference  
19 case for the electricity forecast. Where we also  
20 will attempt to show a band of uncertainty.

21 But we have long since learned that our  
22 single point projections are always wrong and not  
23 always helpful.

24 MR. SCHILLER: So the work will include  
25 the uncertainties in the projections and what the

1 influences are?

2 ASSOCIATE MEMBER GEESMAN: To the best  
3 of our effort to do so.

4 MR. SCHILLER: Thank you.

5 MR. EMMRICH: I do want to comment on  
6 that also. The point being, whatever forecast we  
7 show you, that's the most probable. That means  
8 it's a 50 percent chance that it's going to be  
9 higher and a 50 percent chance it's going to be  
10 lower (laughter).

11 MR. SCHILLER: Exactly, yes.

12 MR. EMMRICH: And of course for rate-  
13 making purposes, because a lot of our forecasts  
14 are for rate-making purposes, you do have to have  
15 one forecast for rate-making purposes. But there  
16 is no such thing as a wrong forecast. It is just  
17 your estimate knowing that it is going to be  
18 higher or lower out in time.

19 MR. SCHILLER (FROM THE AUDIENCE): But  
20 in terms of use of the information, if you use  
21 that for a rate forecast you have to have a number  
22 in that. But in terms of establishing public  
23 policy, understanding the range is important.

24 MR. EMMRICH: I totally agree with you.  
25 For planning purposes we do Monte Carlos, which

1 gives us a full range of probabilities and that's  
2 what you should use for planning purposes.

3 MR. SCHILLER (FROM THE AUDIENCE): Thank  
4 you.

5 MR. TAVARES: Well thank you very much.  
6 Actually we have improved. Our probabilities are  
7 much better. We are 100 percent certain that our  
8 predictions are going to be wrong (laughter).

9 Anyway, with that note --

10 ASSOCIATE MEMBER GEESMAN: That's our  
11 motto, often wrong but never uncertain (laughter).

12 MR. TAVARES: Correct. By the way, if  
13 you can hold on a little bit about -- we're going  
14 to be talking this afternoon about uncertainties  
15 so the discussion will come up in just an hour, an  
16 hour and a half.

17 Next we have Mike Purcell and he is  
18 going to speak about supply of natural gas. So  
19 Mike.

20 MR. PURCELL: Good afternoon, everybody.  
21 The first thing I wanted to say is I wanted just  
22 to clear up, I think, what Herb just said. That  
23 when we talked about the resources in North  
24 America being all in play in the model, they  
25 aren't. Both coasts are shut off so they can't

1       come into play. The east coast of Florida is shut  
2       off so it can't come into play. There's areas in  
3       the Rocky Mountains that the reserves are there  
4       but they're shut off as well because they can't  
5       come into play.

6                ASSOCIATE MEMBER GEESMAN: Which ones  
7       are those? It was the Western US onshore resource  
8       that I think may be confusing to me. I had  
9       understood from this morning's presentation that  
10      all of the onshore resource in the Western US was  
11      in fact considered to be available and subject to  
12      an economically calculated development schedule.

13              MR. PURCELL: The place I'm familiar --  
14      On the west coast I believe that's true. But as  
15      far as in the Rocky Mountains I know there's  
16      resources that are shut off.

17              ASSOCIATE MEMBER GEESMAN: Okay.

18              MR. PURCELL: Because, you know, it's in  
19      a national park, it's in a wilderness area, those  
20      kind of things. It's not going to come on. And  
21      there was even, you know, restrictions based on,  
22      you know, that you can only drill certain times of  
23      the day. Those kind of things were factored into  
24      the NPC work. So there is a significant amount of  
25      the resources in those areas that are shut off.

1 And then obviously both the coasts and the east  
2 coast of Florida are shut off as well. So I just  
3 wanted to make sure everybody understood that.

4 Anyway, my presentation today is just on  
5 the supply picture. Centered on California but it  
6 also deals a lot with what is happening in North  
7 America.

8 To start with our conclusions. In  
9 contrast to previous work that we have done we're  
10 finding now, we're projecting that the resource  
11 and supply for North America is declining. It is  
12 not increasing as is the case with the EIA  
13 forecast, the current EIA forecast, even in the  
14 2007 AEO.

15 We also say that natural gas from Alaska  
16 North Slope and Arctic Canada is not going to  
17 reach into the Continental United States during  
18 the forecast period.

19 ASSOCIATE MEMBER GEESMAN: How long is  
20 the forecast period?

21 MR. PURCELL: To 2017. And really I  
22 think even in our out year times looking at this  
23 we're saying maybe 2022, 2023 for those resources.

24 ASSOCIATE MEMBER GEESMAN: So that is a  
25 change from what you assumed in 2005.

1                   MR. PURCELL: Yes. And that's a major  
2 change. The big change that I think since 2005  
3 besides the supply of resources from Canada and  
4 Alaska is that we are really showing now that LNG  
5 is going to be a major factor and a major supply  
6 source for California and for the Continental  
7 United States, North America. And I have several  
8 slides, I'll show that in a minute.

9                   The other thing that is going to change  
10 around is we feel that gas is going to be  
11 displaced from the Southwest by LNG that is going  
12 to come in from Costa Azul. So that is going to  
13 change the equation a little bit, especially in  
14 Southern California.

15                   We feel that supply from the Rocky  
16 Mountains is going to remain relatively constant  
17 and will have about the same volumes of gas  
18 flowing to us on the Kern River pipeline during  
19 the forecast period.

20                   And the last thing I'll get into is just  
21 some earlier work that Bob Logan and myself had  
22 done earlier this year. Just looking at the  
23 changes in EIA's forecast and the changes in how  
24 much gas is being produced in the US, how much  
25 drilling we're doing. Just some of the trends

1 that are going on in production in the US and  
2 Canada.

3 ASSOCIATE MEMBER GEESMAN: Before you  
4 change slides let me make certain I understand the  
5 implication of your last bullet there. Is it that  
6 the LNG will be priced lower than gas coming from  
7 the Southwest into California?

8 MR. PURCELL: I assumed, you know, I'm  
9 not -- Yes that's true because it will displace  
10 Southwest gas. So that's an implicit assumption.

11 ASSOCIATE MEMBER GEESMAN: So that's an  
12 economically driven displacement.

13 MR. PURCELL: Exactly. And I have got a  
14 table with some colors that shows that pretty  
15 well.

16 This is our projection from the model of  
17 the North American natural gas supply from North  
18 America, obviously, with no LNG. And you can see  
19 the big blue one is the US, the lighter blue is  
20 Canada and the yellow is Mexico. But during this  
21 time you can see that the overall amount of  
22 production is not increasing as EIA's forecast  
23 says. It's pretty flat to slightly declining.

24 ASSOCIATE MEMBER GEESMAN: And what's  
25 going on in Canada?

1                   MR. PURCELL: The same thing. It's  
2 decreasing as well.

3                   ASSOCIATE MEMBER GEESMAN: So that's  
4 not, that's not a tar sands driven reduction,  
5 that's production-related.

6                   MR. PURCELL: Overall production, yeah.  
7 It's not -- You know, it doesn't take any away for  
8 use or anything like that.

9                   ASSOCIATE MEMBER GEESMAN: Okay.

10                  MR. PURCELL: That's just gross  
11 production. The next slide just shows the US  
12 production. Again you can see there is a slight  
13 decline here. It's about five percent overall and  
14 about half a percent per year. The same places  
15 are going to be the big supply sources. You can  
16 see the yellow is Texas, the pink is the Gulf of  
17 Mexico and the light purple is the Rocky  
18 Mountains, which stays pretty constant throughout.

19                  The next slide is the same chart as  
20 before except with LNG coming in to satisfy  
21 demand. And you can see that there's a lot of LNG  
22 going to come in to North America that we're  
23 forecasting through the period to 2017.

24                  Here is our idea for the imports. What  
25 we tried to do is organize the legend so it makes

1 some sense. But in the lower part are all the  
2 operating LNG terminals. Then the Nova Scotia and  
3 Baja Mexico. Excuse me, not the US but in North  
4 America.

5 Nova Scotia and Baja Mexico are under  
6 construction. Also the Freeport and Louisiana  
7 Sabine Pass is under construction. Then there's  
8 the two approved ones, Cameron and Corpus Christi.  
9 The South Atlantic and Golden Pass/East of River,  
10 which is another Gulf Coast LNG terminal are  
11 projected, are proposed right now.

12 But that's a lot of LNG. It's about 24  
13 Bcf a day to come in by the end of the forecast  
14 period. But I think, you know, to note that. You  
15 think about, well gosh, is there enough LNG in the  
16 world. If you listened to Mr. Jensen's talk this  
17 morning his low case was projecting at 2017 about  
18 40 Bcf a day of available LNG being liquefied in  
19 the world and his high case was well over 50,  
20 closer to 60 billion cubic feet a day. So there's  
21 that much gas that is going to be liquefied.

22 The question then becomes, you know, how  
23 much of it will actually come here? You know,  
24 price is going to determine that. And also, you  
25 know, the other issues that he spoke about too

1 which were geopolitical and those type of  
2 concerns. The model runs on the economics and the  
3 economics say it should come here.

4 This is just the same slide except it  
5 doesn't have any of the international terminals in  
6 it so you can see we're about a little under 21  
7 Bcf a day. And again, the majority of the gas is  
8 coming in to the Gulf Coast. And we did not in  
9 our model run this time have a terminal on the  
10 West Coast except for Costa Azul. There's not one  
11 in California, there is not one in this  
12 projection.

13 ASSOCIATE MEMBER GEESMAN: Are Cameron  
14 and Corpus Christi Sempra projects?

15 MR. PURCELL: I'm not sure.

16 MR. PAK: Cameron is and Corpus Christi  
17 is not.

18 ASSOCIATE MEMBER GEESMAN: Okay.

19 MR. PURCELL: This slide talks a little  
20 bit of what we were talking about before. But you  
21 can see some of the interplay of when natural gas  
22 begins to come in to Costa Azul. And you can see  
23 here that the yellow represents the gas that we  
24 think will come in to SDG&E's system directly  
25 across the border. That will come in directly

1 across the border is in the yellow. And then the  
2 white up here is what we believe, or our modeling  
3 anyway, that will come all the way around and come  
4 in through Topock.

5 But you can see that we're losing a  
6 little bit. You can see the Southwest get backed  
7 off by that. However our Rockies supply stays  
8 relatively the same. Our California production  
9 is, you know, declining but staying up fairly well  
10 through the forecast period. But it is going to  
11 change the dynamic in Southern California as far  
12 as where gas comes in and comes out.

13 ADVISOR JONES: So Mike, let me just  
14 clarify here.

15 MR. PURCELL: Sure, sure.

16 ADVISOR JONES: In, what is it, 2013 you  
17 have no deliveries on Blythe, at Blythe. They're  
18 backed out completely.

19 MR. PURCELL: From Mexico? I'm sorry.

20 ADVISOR JONES: From the Southwest.

21 MR. BRATHWAITE (FROM THE AUDIENCE):

22 Yes. By 2013 --

23 MR. PURCELL: Yes.

24 MR. BRATHWAITE (FROM THE AUDIENCE): --

25 all the supplies were backed out, yes.

1                   MR. PURCELL: Well, they will almost all  
2 be backed out.

3                   ADVISOR JONES: Okay.

4                   MR. PURCELL: That's the way it's coming  
5 out right now.

6                   The next slide is -- We're getting to  
7 the end here but I just wanted to talk a little  
8 bit about US production in the main, I guess. You  
9 can see that these are the various forecasts from  
10 vintage, you know, the annual energy outlook from  
11 EIA since 2002.

12                   And in 2002 you can see that at the end  
13 of the forecast period we were talking about well  
14 over 33 Tcf of gas. And as every year has gone by  
15 things have gotten lower and lower and now in my  
16 2007, you know, we're only talking maybe 27 Tcf of  
17 gas at the end of the forecast period. So it's  
18 dropped quite a bit. And I think it's a  
19 reflection of what we're seeing nationally in our  
20 production trends. You know, we're drilling a lot  
21 and we're not finding that much more gas.

22                   This slide is just to show you  
23 historical natural gas production since 1936. And  
24 you can see that gas peaked in 1971. Then in 2002  
25 it even got, was at the all-time high and since

1 that time it has been tailing off. But it's still  
2 relatively high. But we're drilling a heck a lot  
3 of wells to maintain this production right now.

4 This slide is interesting in that it  
5 shows the production from various vintages of  
6 wells and how long it took for them to produce  
7 their gas. And you can see back in 1980, this  
8 purple band, that gas took a long time to be  
9 produced. And as you can see as you move across  
10 the various vintages out to the last couple of  
11 years the decline curve is very steep.

12 So what that translates to is most of  
13 the gas is being produced out of wells in the  
14 first year. And that reflects that we've drilled  
15 into smaller reservoirs. It reflects that we're  
16 drilling more unconventional production, which is  
17 shale gas, tight sands, coal-bed methane. Their  
18 production falls off rapidly but can operate then  
19 at a lower level for a long time.

20 This graph shows the gross production in  
21 the United States, which is the orange line, since  
22 1995 all the way through 2006. And it shows the  
23 price of natural gas in nominal dollars since then  
24 out to, you know, 2006 again, and then it shows  
25 the number of natural gas wells that have been

1 drilled during that time.

2 And you can see in 1995 we were drilling  
3 maybe 8,000 natural gas wells. In 2006 we drilled  
4 over 31,000 natural gas wells. And this chart is  
5 very telling in that it shows how our production  
6 has changed and what we're drilling for. We're  
7 drilling for smaller accumulations, we're drilling  
8 for a lot of unconventional production. which  
9 again is coal-bed methane, tight sands. Those  
10 kind of prospects that just don't have the  
11 reserves behind them. And in order to maintain  
12 production we're going to have to keep drilling  
13 and drilling a lot.

14 The little note that is on here is  
15 because there has been so much drilling, if you  
16 really look at the losses from Katrina -- which is  
17 if you put it back in there's about maybe a half  
18 to Tcf to three-quarters of a Tcf that were  
19 knocked out by that hurricane. It's also  
20 interesting to note that in 2004 Ivan hit too so  
21 there was some curtailment of production in that  
22 year as well. So that's why I think those two  
23 years are down more than they would have been.

24 And if you look at the little blue arrow  
25 there that I tried to construct on this, it just

1 kind of would show if that production was added  
2 back in where the production would be in the US.  
3 But, you know, it may mean that we're a little  
4 more level or maybe slightly up but it is  
5 certainly not a drastic improvement. You know, we  
6 haven't turned the corner and all of a sudden  
7 we're finding all this gas again.

8           You know, I say this then with the note  
9 as well and something that's cautionary. That  
10 just because this is happening now doesn't mean  
11 that this is the way gas production is going to  
12 stay. You know, there's technology increases.

13           You know, they're figuring out new ways  
14 to drill into the shale plays. New ways to  
15 fracture, new proppings to use to hold the  
16 fractures open. You know, there's people, you  
17 know, working on this very hard so there's still  
18 the possibility that production could be  
19 increased. But it's going to take some technology  
20 and a heck of a lot of money to make that happen.  
21 On our onshore resource anyway.

22           That's it for my presentation. Does  
23 anybody have any questions? Yes.

24           MR. BILLINGS: Kevin Billings with Kern  
25 River. Can we go back to your second slide on

1 conclusions?

2 MR. PURCELL: Maybe. Yes.

3 MR. BILLINGS: Okay, I have a question.

4 MR. PURCELL: Okay.

5 MR. BILLINGS: Specifically, it kind of  
6 reminds me, your second point there, if you're  
7 going to poke someone in the eye use a big stick.  
8 From Kern River's perspective here you're talking  
9 about supply. And you say in 2009 when Rockies  
10 Express comes on line the Rockies are going to  
11 decline. And that would be gas coming down  
12 through Kern River.

13 MR. PURCELL: Right.

14 MR. BILLINGS: My question is, this  
15 morning Bill Wood shows on his pricing that the  
16 Rockies is the most competitively priced gas.

17 MR. PURCELL: Right.

18 MR. BILLINGS: And then the other point  
19 being, Kern River is fully contracted. I mean,  
20 we're at maximum capacity now on firm take or pay  
21 contracts. I guess that strikes -- the irony of  
22 that is why would the cheapest gas on a pipeline  
23 that is fully contracted not come to the  
24 California markets?

25 MR. PURCELL: Well, it's just -- I'm not

1 exactly sure and that's a good question. But what  
2 we showed on there was just that there's -- when  
3 that pipeline first came on that the production  
4 dropped about 200 Mcf a day going to, going on to  
5 Kern. And then after about 2013 or something it  
6 went back up to the normal level.

7 MR. BILLINGS: Okay.

8 MR. PURCELL: And I don't know if that's  
9 an artifact in the model. Leon may be able to  
10 address that better. But that's just the way the  
11 dynamics in the model equated that.

12 MR. BILLINGS: Then let me ask --

13 MR. PURCELL: And our model doesn't have  
14 the, I guess it doesn't have the knowledge that it  
15 is fully contracted or they have to have this much  
16 gas, you know.

17 MR. BILLINGS: Okay.

18 MR. PURCELL: Those kind of factors  
19 don't go into that.

20 MR. BILLINGS: All right. The next  
21 question would be, what is the source then for the  
22 production increase? Because I think everyone --  
23 Not everyone, I'm not going to make that broad of  
24 a generalization. But a lot of people in here  
25 utilize they service of George Lippman and Lippman

1 Consulting for forecasting models. I'm sure the  
2 CEC uses them.

3 I mean, he's well used within the  
4 industry. And his models that he has show that  
5 production will increase, will continue to  
6 increase and it will out -- production in the  
7 Rocky Mountains will outpace the natural gas that  
8 will go out to the Rockies --

9 MR. PURCELL: Go out of the Rockies to  
10 go east.

11 MR. BILLINGS: -- that will out to the  
12 Midwest on the Rockies Express. So I'm  
13 questioning, where is the source for this data  
14 also then?

15 MR. PURCELL: Well the data that we get  
16 is again from the NPC data. You know, the various  
17 cost curves for the Rocky Mountains. So it's a  
18 function of how it's computed inside the model.  
19 So there is that production there. And it's  
20 looking at the overall production and balancing,  
21 you know, where is it going, what sources is it  
22 going to go to. And we're showing that during the  
23 forecast period that production in the Rocky  
24 Mountains does increase.

25 MR. BILLINGS: An increase that is

1 significant?

2 MR. PURCELL: Yes.

3 MR. BILLINGS: Anyway, that just, that  
4 really, really catches me off guard and I think  
5 that's a bust.

6 MR. PURCELL: I think, you know, it  
7 might be not as --

8 MR. BILLINGS: That's a bust. That's my  
9 opinion that that's a bust.

10 MR. PURCELL: Yeah, it could be.

11 MR. BRATHWAITE: Could I ask a question?  
12 When you say it's a bust, I mean, what do you  
13 mean? Okay, the Rockies Express coming on in 2009  
14 in the model.

15 MR. BILLINGS: Sure, yes.

16 MR. BRATHWAITE: It fills up going east.  
17 It is no doubt about that. But Kern River does  
18 not lose any flows going west. In my presentation  
19 in a little while we'll show you that there is no  
20 loss of Kern River flows during the, during the  
21 forecast period.

22 MR. BILLINGS: But that's not what that  
23 was saying.

24 MR. PURCELL: Yes, because it drops  
25 about --

1 MR. BILLINGS: That's saying that  
2 Rockies production declines.

3 MR. PURCELL: -- about 200 a day during  
4 the forecast period. Right there.

5 MR. BRATHWAITE: Well then I'll take a  
6 second look at that, okay. I'll take a second  
7 look at that.

8 MR. BRATHWAITE: Yeah, I would just  
9 appreciate that. You know, that's --

10 MR. BRATHWAITE: But overall though,  
11 overall Kern River does not lose flows during the  
12 forecast period. I mean, we may have some little  
13 dips up and down, I'm not going to, I'm not going  
14 to argue about the blips. But in terms of like  
15 the overall it does not lose any flows coming  
16 west. I hope that answers your question.

17 MR. BILLINGS: Yeah.

18 MR. PURCELL: Yes Al. I'm sorry, I  
19 didn't -- I wasn't looking, go ahead.

20 MR. COX: Rory Cox from Pacific  
21 Environment. Now you mentioned that the Southwest  
22 natural gas was going to be, was going to be  
23 competitive with the LNG and that would decrease  
24 Southwest supplies.

25 MR. PURCELL: Right.

1           MR. COX: But isn't it also -- I mean,  
2           what role does the -- The Public Utilities  
3           Commission in 2004 passed a ruling which allows  
4           SDG&E and the gas company to not re-up those  
5           Southwest contracts to make room for the LNG. So  
6           given that they have that regulatory permission to  
7           not buy Southwest in favor of the LNG what role  
8           does price competition really play there?

9           MR. PURCELL: Well in our model none of  
10          those legal or -- those type of constraints aren't  
11          in there. So it's just a matter of this is the  
12          price that's driving that. So we don't have a  
13          factor in there I don't think. Is that not true?

14          MR. BRATHWAITE: Let me, let me answer  
15          this one.

16          MR. PURCELL: Okay.

17          MR. BRATHWAITE: It is true, we cannot  
18          directly take in consideration any sort of legal  
19          constraints that may be placed upon production or  
20          anything like that. However, if we believe or if  
21          there is some information that comes to us that  
22          have us believe that something will be delayed in  
23          terms of its construction or in terms of its flows  
24          or anything like that we can make it that the --  
25          whether it's a pipeline, whether it's an energy

1 terminal or anything like that, we can make sure  
2 that that does not flow until say maybe 2015,  
3 maybe 2020 or something like that.

4 A good example of that, I think  
5 Commissioner Geesman was asking about this a short  
6 while ago, is the situation with the Alaska  
7 pipeline. Now in 2005 we thought this was going  
8 to come on in 2013 and 2016 for those two  
9 pipelines up in the Arctic.

10 Since then we have reevaluated, we have  
11 looked at it, we have spoke with some of the  
12 industry folks, and we have now put that off until  
13 2020 and 2022 and we're not even sure it's going  
14 to come on even then. But the fact of the matter  
15 is it is now outside our forecast and our forecast  
16 horizon.

17 So in terms of putting constraints in  
18 the model we can do so without directly dealing  
19 with the issue that you just raised. I hope that  
20 answers the question.

21 MR. PURCELL: We haven't done that.

22 MR. BRATHWAITE: On which one are you  
23 talking about?

24 MR. PURCELL: His issue with those  
25 supplies in the Southwest. We haven't put that

1 constraint in the model right now.

2 MR. BRATHWAITE: No, not right now but  
3 it could be done.

4 MR. PURCELL: Right, it could be done  
5 but it is not there.

6 Dale, do you want to -- go ahead.

7 DR. NESBITT: Go ahead.

8 DR. ARTHUR: Dave Arthur, City of  
9 Redding. To sort of pick up on that theme a  
10 little bit.

11 It seems to me that if we're going to  
12 have 24 Bcf at the end of the period that  
13 represents a meaningful percentage of US supply.  
14 And from this morning I learned that Russia and  
15 Iran are a predominant source of supply and  
16 probably even more so in that type of time frame.  
17 I'm not sure that's right but that seemed to be  
18 what one of the charts was suggesting. So that  
19 would suggest that political considerations might  
20 be fairly significant.

21 And so my question is, since we have an  
22 illustrious history, not simply in California but  
23 throughout the West and even North America of  
24 having political decisions having pronounced  
25 impacts on economic models, is it possible to run

1 politics as usual in your model so we understand  
2 how politics might cause disruptions that we  
3 otherwise weren't predicting for what economics  
4 would tell us?

5 MR. BRATHWAITE: The answer to your  
6 question is yes, we could run politics as usual  
7 and we could run dangerous politics or we could  
8 run whatever politics you wish to run. The point  
9 is though, if we believe --

10 For instance you just raised the issue  
11 of Iran. If we believe that Iran is not going to  
12 be supplying any liquefaction capacity to the  
13 world we could shut it off. And that would be,  
14 that would be the politics, taking the  
15 geopolitical uncertainties and putting that into  
16 consideration in our model. That could be done.

17 The point is though we just have to  
18 develop the scenario to deal with whatever issues  
19 that you or anybody else in our audience might  
20 choose to raise.

21 MR. PURCELL: Dale.

22 DR. NESBITT: Dale Nesbitt, Altos.

23 On this question of price competition.  
24 Let's go away from the model and go to the real  
25 world, although I agree there is not much

1 difference. Now, how does the real world work on  
2 price competition? There is a price. There is a  
3 price and everybody is a price taker. And if you  
4 put more into a market the price goes down but  
5 you're still the price taker.

6 And so this issue of price competition  
7 between Southwest gas and LNG really isn't very  
8 complicated. There's a price a Topock. Whoever  
9 can make profits at that price produces and sells  
10 and whoever can't, doesn't. And so the issue --

11 The other issue in Rocky Mountain gas,  
12 which has gotten a lot of attention recently  
13 because I don't think people understand Rocky  
14 Mountain's gas as well as we should. The point  
15 Kevin made is that Rocky's is the cheapest gas on  
16 the continent. I don't think people believe that  
17 in general in the industry.

18 The Rockies gas, you have tight  
19 formations in the Green River Basin, you have the  
20 Uinta Basin gas. These are very tight. The  
21 fields are one Bcf or less. If you ask Anadarko  
22 Petroleum who publishes estimates all the time  
23 they talk about the full cycle production cost of  
24 Rocky Mountain's gas exclusive of reserves today  
25 at \$8. So it's not clear what the production cost

1 of Rocky Mountains gas is.

2 If we use oil as an analogy, think about  
3 oil. Nobody really wonders why it is that  
4 domestic production is only 40 percent of the  
5 total. It's because that's all the oil you can  
6 get out of the ground at 60 bucks, that's why.

7 And that's kind of the simulation that  
8 these guys try to do here is to say, let's take  
9 that same model. Not that it's the real world but  
10 it gives us a nice economic benchmark for a base  
11 case. And talk about cost-on-cost competition in  
12 a world where the price is set by gas-on-gas and  
13 gas-on-oil competition.

14 So don't read more into it than that.  
15 It is just an economic reference case that was  
16 used to put together four scenarios and to really  
17 start thinking about these uncertainties. Because  
18 the minute we think we're certain about Rocky  
19 Mountains gas production costs I'm pretty sure  
20 we're uncertain.

21 MR. PURCELL: Thanks.

22 MR. PAK: Al Pak for Sempra LNG. I have  
23 a correction that I can offer you and a comment.  
24 And it was really helpful to go after the last  
25 speaker because he pointed out some kind of a -- I

1 think part of the question that I have for you  
2 following the correction has to do with the market  
3 anomalies that get displayed in the tables and  
4 charts that you have provided.

5 First of all, the correction. The  
6 Cameron facility is not only approved, it's under  
7 construction. It's completion lags the Costa Azul  
8 facility by about eight months so our expectation  
9 is that sometime either September or fourth  
10 quarter of 2008 that facility will be fully  
11 operational and available at 1.5 Bcf per day. We  
12 recently got a permit change approved by the FERC  
13 that upped the capacity, available capacity at  
14 that facility and we're constructing to that limit  
15 right now.

16 ASSOCIATE MEMBER GEESMAN: Do you have  
17 one other Gulf Coast project?

18 MR. PAK: Yes, and I was going to say  
19 that's the other thing I want to add. We have the  
20 Port Arthur facility that recently received its  
21 FERC certificate and the final investment decision  
22 on that project is pending our -- We are currently  
23 marketing the capacity at that facility. And the  
24 minute we hit what we consider acceptable levels  
25 of contracting, forward contracting on the

1 capacity we'll go ahead and commence construction  
2 there.

3 The question I have, I think, as I said  
4 the last gentleman addressed this. When we look  
5 at the flows from the LNG facility at Costa Azul  
6 to Blythe in the years 2010 and 2012 those  
7 supplies according to the model aren't flowing.  
8 That also happens to coincide with the price  
9 projections that Bill Wood provided this morning.

10 So the sawtooth pricing that you saw as  
11 price falls in 2010 apparently the model is  
12 representing that Costa Azul supplies will not  
13 flow north to Ehrenberg. And the same thing  
14 happens, the price rises in 2011 and apparently we  
15 flow according to the model. And in 2012 that  
16 flow induces another price decline and we're shut  
17 out in 2012. I think, you know, if there is a way  
18 to do this --

19 And I'm kind of asking if what I'm  
20 saying is correct? Is that just a model anomaly  
21 and can it be corrected just in the narrative of  
22 the modeling results that that's actually  
23 marketing contest? We consider that to be a  
24 contestable market.

25 We don't expect the Baja Norte and North

1 Baja pipelines to be dry in the years because San  
2 Juan or Topock or, I'm sorry, Permian, we get a  
3 lower price and we're out of market and they're  
4 in. I think that's all contestable market and I  
5 think it's represented better in the out years  
6 than it is in the early ones.

7 But because we saw the price fluctuation  
8 and the flow fluctuation coinciding with one  
9 another we don't want to have the state  
10 representing to the Legislature and the Governor  
11 that Costa Azul is the swing facility. We don't  
12 expect that to be the case.

13 MR. BRATHWAITE: Yes. I fully accept  
14 your comments here. The point, the point I wanted  
15 to make is that these are all preliminary results.  
16 That problem that you so rightfully point out is  
17 correctable and will be corrected.

18 I must admit that right now during this  
19 process we are quite pressed for time in terms of  
20 getting this thing put together. There are  
21 certainly some, shall we say, bumps in the road  
22 that need to be leveled out and straightened out  
23 and I promise you it will be so corrected.

24 MR. PURCELL: Anybody else? Thank you.

25 MR. TAVARES: Well thank you very much.

1 Leon is going to make a presentation on the  
2 infrastructure. I think Commissioner Geesman had  
3 a question this morning so go ahead and start your  
4 presentation and Commissioner Geesman, whenever  
5 you have --

6 MR. BRATHWAITE: Good afternoon. I'm  
7 Leon Brathwaite, I work in the natural gas unit  
8 upstairs. I do most of the modeling work around  
9 here. So any problems with the model, our  
10 modeling work, it's my fault. No, that was a  
11 joke. That was a joke, it was a joke.

12 Okay, I am going to talk about the  
13 infrastructure and some of the results that came  
14 out of the model in some of our work. What I will  
15 present will be California-centric. There are a  
16 lot of issues outside of California that I will  
17 not present.

18 Some of the issues have already been  
19 spoken about by Bill this morning in particular  
20 and some of the other issues that we saw early on  
21 this morning. So I will not repeat them here but  
22 they are certainly relevant to our discussion.

23 Okay. So what I'll first talk about,  
24 the major findings, and then we'll look at some  
25 particular slides just to show what these major

1 findings say. Okay.

2 During the forecast period nearly all  
3 major pipelines will operate below 100 percent  
4 capacity factor. Kern River, however, hovers  
5 around 80 percent to 85 percent capacity factor.

6 Now I want to put this in context. Kern  
7 River delivers a substantial amount of gas  
8 upstream of the California leg of the pipeline.  
9 They deliver a lot of gas in Southern Nevada to  
10 some of the power plants there. So they deliver  
11 the maximum amount of gas, even though it's only  
12 80 to 85 percent of the capacity that comes to  
13 California.

14 They are delivering the maximum amount  
15 of gas that could be delivered to California right  
16 now. So I just wanted to put that in context. It  
17 does not -- I was not intended to mean that Kern  
18 could deliver more gas if so called upon.

19 ASSOCIATE MEMBER GEESMAN: So where do  
20 you lose the 200 million cubic feet per day from  
21 the Rockies?

22 MR. BRATHWAITE: Two hundred million  
23 cubic feet per day?

24 ASSOCIATE MEMBER GEESMAN: It was in  
25 Mike's presentation.

1                   MR. BRATHWAITE: Well I would imagine  
2                   that's probably a little bit upstream at some of  
3                   those power plants. There are several there about,  
4                   I don't know how many. Kevin, how many power  
5                   plants do you have upstream of the California leg?

6                   MR. BILLINGS: Kevin Billings, Kern  
7                   River. Kern River provides natural gas service to  
8                   eight large natural gas-fired power plants in  
9                   Nevada and then two in Utah.

10                  MR. BRATHWAITE: Okay, thank you, thank  
11                  you.

12                  MR. BILLINGS: And just to be specific  
13                  about that, the other subject. Kern River  
14                  delivers approximately 85 percent of the natural  
15                  gas consumed in Southern Nevada. So it is being  
16                  siphoned off before it gets to California is what  
17                  Leon is saying.

18                  MR. BRATHWAITE: Thank you, thank you.  
19                  Okay. So all other pipeline systems, other major  
20                  pipeline systems that serve California hovers  
21                  around 50 percent. In some cases falls below 50  
22                  percent, as you will see shortly.

23                  LNG entering California displaces  
24                  traditional natural gas supplies from the  
25                  Southwest. Now I want to be clear about this.

1 The LNG that is entering California, it is an  
2 estimate that we have. Because when that gas gets  
3 around the horn and gets back to the Blythe-  
4 Ehrenberg area. There are several options as to  
5 the way it can go so we are just making estimates  
6 as to what will actually enter California.

7 Okay, the assessment projects that only  
8 two pipelines affecting California will expand.  
9 These pipelines are TGN, which travels between  
10 Mexico and San Diego, and the North Baja line.

11 After Costa Azul comes on line both of  
12 these pipelines will expand to accommodate the  
13 flow of regasified LNG. TGN will reverse and  
14 instead of going south will now go north into San  
15 Diego and North Baja instead of going west will  
16 now east and deliver gas into Blythe/Ehrenberg.

17 Okay, capacities and flows at the  
18 California border. Here we see what is happening  
19 at Malin. We see that the capacity utilization  
20 starts off around 60 percent or so and then sits  
21 around the 50 percent line, declining slightly in  
22 the outer years at the end of the forecast period.  
23 By that time we are looking at about 40 to 50  
24 percent capacity utilization at Malin.

25 This is Kern River. And you see the

1 Kern River capacity utilization hovers around 80  
2 to 85 percent. And again keeping in mind the  
3 comments that was just made by Kern River that  
4 this is all the gas that can be delivered at this  
5 point in time given their upstream commitments.  
6 So Kern River has no more gas to deliver into the  
7 California market. So they are, probably you can  
8 say probably fully utilized at this time.

9 ADVISOR JONES: Can I ask a question  
10 about the last graph?

11 MR. BRATHWAITE: Yes. This one?

12 ADVISOR JONES: So what accounts for the  
13 dips like in 2011, 2013? It's not even throughout  
14 the years.

15 MR. BRATHWAITE: We do have some price  
16 variations that occur throughout the forecast  
17 horizon. And as prices change a little bit along  
18 the way you see these changes in flows and supply  
19 as the price differentials change and you see  
20 these sort of changes.

21 Also in light of that Kern River also  
22 does some deliveries, substantial amounts of  
23 deliveries upstream of this measurement. So  
24 between those two things, yes, we do see some of  
25 these dips occurring as you go through the

1 forecast horizon.

2 But you will notice at the end of the  
3 forecast horizon we are up well over, they are  
4 probably all 90 percent. But you will see the  
5 blips during the forecast period, yes.

6 Okay, this is what is happening at  
7 Topock. At first capacity utilization rises at  
8 Topock but then falls off and falls below 50  
9 percent by the end of the forecast period. And  
10 this is gas out of the Southwest. A lot of this  
11 displacement is -- a lot of the reduction in  
12 capacity utilization is the result of LNG flows.

13 And here we see what is happening at  
14 Blythe/Ehrenberg. And this goes to the comment  
15 that was made by Semptra about the zero flows in  
16 2010 and 2012. I will correct these things and  
17 stuff. But what this graph does show though, it  
18 does show, is the LNG coming in and displacing  
19 Southwest flows. This is what is really happening  
20 here. You see Southwest flows dropping off  
21 substantially, eventually reaching zero, and LNG  
22 is taking its place in the outer years.

23 ASSOCIATE MEMBER GEESMAN: And the only  
24 other LNG you assume on the West Coast is Costa  
25 Azul?

1 MR. BRATHWAITE: That is correct, yes.

2 ASSOCIATE MEMBER GEESMAN: Costa Azul at  
3 its current plan size, no expansion?

4 MR. BRATHWAITE: There will be  
5 expansions around 2013. But in the early years,  
6 yes. Between 2008 and 2013 at its current  
7 capacity design.

8 ASSOCIATE MEMBER GEESMAN: If LNG is  
9 winning a price competition in your model with  
10 Southwestern gas, it looks fairly soon, wouldn't  
11 the economic nature of your model snap its finger  
12 and have another terminal?

13 MR. BRATHWAITE: Commissioner, one of  
14 the things that I do note exactly in the model,  
15 and this is not presented here, is that once Costa  
16 Azul comes on that thing fills up almost  
17 immediately. So the answer to your question is  
18 yes. As a matter of fact, if I allow that model  
19 to go as it so pleases economically, for want of a  
20 better word, yes, we will have more terminals in  
21 the Mexico Baja area, yes.

22 ASSOCIATE MEMBER GEESMAN: But you  
23 haven't incorporated that into this model?

24 MR. BRATHWAITE: No, it is not  
25 incorporated.

1           Okay, the overall supply outlook for  
2 California. What this graph shows is the decline  
3 in Southwest flows occurring in this area and the  
4 expansion of LNG flows occurring up here. That is  
5 the main point of this graph. Everything else  
6 seems to hold its current, it's current  
7 percentage. There is some variation of it but the  
8 main two things is to look at what is happening in  
9 the Southwest in this area and what is happening  
10 to LNG in this area up here. So this is the main  
11 point of this graph.

12           This takes me to the end of my, of my  
13 presentation. However, there are a couple of, two  
14 points that I would like to make that are relevant  
15 to infrastructure. One being the construction of  
16 the Rockies Express which comes on in 2009. That  
17 was already mentioned. That takes gas east. That  
18 does have some effect upon the overall supply and  
19 demand outlook in North America. The Rockies  
20 Express does fill up once it comes on in 2009.

21           The second thing is the substantial  
22 construction of LNG facilities in the Gulf of  
23 Mexico in particular. And there too we are seeing  
24 quite a lot of activity in terms of LNG flows and  
25 regasification occurring in the Gulf of Mexico.

1           But that's about it. But those things  
2           were mentioned previously so I didn't put it in my  
3           presentation. So I'll take any questions or  
4           comments you may have right now.

5           ASSOCIATE MEMBER GEESMAN: Just to  
6           confirm what was said earlier, no Alaskan or  
7           Arctic Canada gas during the forecast period comes  
8           into the Lower 48?

9           MR. BRATHWAITE: That is correct,  
10          Commissioner. As a matter of fact in the model we  
11          don't allow that to even be considered to be  
12          available. Alaska is available, I believe, in  
13          2022 and the Mackenzie Delta Pipeline is available  
14          in 2020. So it's all there.

15          MR. YEE: I'm Gary Yee with the Air  
16          Resources Board. My question relates to gas  
17          quality and the issues that are pertaining to the  
18          South Coast Air Quality Management District's  
19          position in terms of importation of LNG with  
20          higher energy content. I know there has been some  
21          discussion, recent discussions/negotiations with  
22          SoCal Gas regarding the bringing in of that  
23          natural gas and accommodating to ensure that it  
24          does not raise the historical average above their  
25          1360 Wobbe value.

1           Now in your presentation here you're  
2           suggesting that 1.5 billion cubic feet of LNG will  
3           be brought into the system. That seems to be a  
4           lot of gas. And if this is higher energy content,  
5           higher Wobbe content gas, I don't see how that is  
6           going to be accommodated for.

7           MR. BRATHWAITE: Okay there are two  
8           things I would like to make, two comments I would  
9           like to make pertaining to your question.

10           Number one, we allowed TGN, which  
11           reverses and flows north during our forecast  
12           horizon, we allow it to expand as it so wishes.  
13           And we are going to be taking a second look at  
14           that to see if that assumption is valid. I think  
15           Bill Wood, my colleague, will tell you that it  
16           probably should be kept and limit the amount of  
17           LNG that flows into San Diego. So that may  
18           address part of the amount, part of the issue in  
19           terms of the amount of LNG that comes into  
20           Southern California.

21           And secondly about the gas, the gas  
22           quality issue. We did not really and truly take  
23           that into consideration in terms of developing  
24           this case. However, there have been some comments  
25           by some of the stakeholders that this is probably

1 a sensitivity or a scenario that we should truly  
2 consider running. And in consultation with the  
3 Committee on the natural gas and the IEPR  
4 Committee we will be taking that into  
5 consideration. Maybe running that scenario and  
6 seeing what effects that will have on the whole,  
7 on the whole infrastructure makeup of the state.

8 MR. EMMRICH: I did want to respond to  
9 that comment. If there is 1.1 Bcf of gas at the  
10 Costa Azul plant, 400 million could go to San  
11 Diego, 300 million a day will probably stay in  
12 Mexico and the remaining 300 million would wind up  
13 at Blythe where it could go Phoenix or into LA.  
14 The amount of gas hitting our system we anticipate  
15 to be fairly small unless that facility is really  
16 expanded into the second phase.

17 MR. BRATHWAITE: Thank you.

18 MR. PAK: Al Pak for Sempra LNG.  
19 Looking at the flows from Costa Azul into the San  
20 Diego system. We had an off-line conversation  
21 where the staff agreed that a mistake had been  
22 made in the representation of the physical  
23 capacity of Otay Mesa. It is at present being  
24 constructed to 400 million cubic feet per day.  
25 And that is largely the result of the CPUC's

1 ruling that new shippers would have to pay for  
2 incremental costs of pipeline capacity and receipt  
3 point capacity and we've done that to the level of  
4 400 million a day.

5 In keeping with this idea that the final  
6 reports will include stochastic and heuristic  
7 analyses, and if I remember correctly from my  
8 college statistics courses that's sort of Latin  
9 and Greek for futzing around with the input  
10 variables. We kind of like the idea that this  
11 should be one of the scenarios that should be  
12 included in those analyses.

13 We have had a lot of discussions with  
14 the Public Utilities Commission about the rate  
15 payer benefits that could take place on commodity  
16 if investment of capital, if capital investment at  
17 the Otay Mesa and downstream facilities were to be  
18 made and paid for by rate payers on a rolled in  
19 basis. And we think that the analysis that  
20 resulted from this mistake, which we sort of  
21 considered a good mistake, is indicative of the  
22 kinds of things that we were seeing as we were  
23 nominating to our affiliated gas utilities the  
24 level of capacity we might be interested in  
25 building there.

1           The price collapse that you saw in the  
2           San Diego system relative to the SoCal system and  
3           in Southern California relative to Northern  
4           California I think are the kinds of results that  
5           could be instructed as to whether California's  
6           current policy on incremental rate making for new  
7           facilities is the right one or whether a rolled in  
8           rate making policy should be reconsidered. And  
9           the PUC has held open the possibility that that  
10          would be done.

11           I heard Bill Wood say this morning that  
12          he saw the mistake and he was going to correct it  
13          and that should absolutely be done for the  
14          reference case. But if you're going to run  
15          stochastic analyses this is not a bad one to keep  
16          in the lineup of scenarios that you have. So  
17          that's the only comment we had there.

18           MR. BRATHWAITE: Maybe, Al, it was not a  
19          mistake right?

20           MR. PAK: That's right.

21           MR. BRATHWAITE: No, it's a joke, it's a  
22          joke.

23           MR. COWDEN: Hi, I'm Bob Cowden, PG&E.  
24          I noticed with, you know, once Costa Azul comes on  
25          line, flows on PG&E's Redwood Path are kind of in

1 the 800 to 900 a day level.

2 MR. BRATHWAITE: Yes.

3 MR. COWDEN: And even though you  
4 indicated there wouldn't be an expansion it seems  
5 like there just has to be a lot of pressure on  
6 PG&E's southern Baja path. And I'm guessing that  
7 in your model that that path flows at a fairly  
8 high load factor after Costa Azul comes on. So I  
9 think even though the model may not want to expand  
10 the pipeline it is likely that there could be a  
11 lot of interest from our shippers in expanding the  
12 line if it is flowing at a real high load factor  
13 over a Bcf a day.

14 MR. BRATHWAITE: Absolutely. Yes I  
15 totally agree.

16 MR. COWDEN: It would be nice to be able  
17 to break out maybe some of the capacity factors on  
18 some of the lines in California in the report just  
19 to see how much loading there is on the lines in  
20 the Southwest.

21 MR. BRATHWAITE: In the final report  
22 I'll certainly make sure that is done, Bob.

23 MR. COWDEN: Okay, thanks Leon.

24 MR. BRATHWAITE: Sure. Questions,  
25 comments? If not, thank you very much for

1 listening to me.

2 MR. TAVARES: Thank you.

3 Commissioner Geesman, if you don't mind  
4 we can take a few minute break.

5 ASSOCIATE MEMBER GEESMAN: Yes. Why  
6 don't we come back at five minutes after three.

7 (Whereupon, a recess was taken  
8 off the record.)

9 MR. TAVARES: We wanted to reconvene  
10 again. We already made all the staff  
11 presentations. Next we have one of our  
12 consultants that is going to help us improve our  
13 100 percent probability of being wrong. Maybe we  
14 can go out to 125 probability (laughter).

15 She is going to discuss the uncertainty  
16 of alternative scenarios. So Catie, why don't you  
17 just go ahead.

18 MS. ELDER: Sure. And I am not going to  
19 probably fix that uncertainty or reduce the  
20 probability of being wrong, I'm just going to tell  
21 you how mammoth it is.

22 I want to acknowledge first, on the  
23 phone listening is a colleague of mine,  
24 Dr. Youssef Hegazy, out of our Seattle office. He  
25 has worked with me primarily on the demand

1 associated with this as well as the price. He  
2 worked on the oil/gas price relationship stuff  
3 that you'll see in the presentation.

4 Youssef was supposed to be able to  
5 interrupt me if he needs to and we hope that's  
6 true. So if you hear this voice coming from  
7 nowhere, this sort of soft-spoken voice coming  
8 from nowhere, hopefully that's Youssef Hegazy  
9 trying to interrupt me and make a point.

10 DR. HEGAZY: I'll try not to make it so  
11 soft.

12 MS. ELDER: There you go, it works.  
13 Great, I'm glad to hear that. Now I have to  
14 figure out which button to push. Page Down is not  
15 working. Arrow, Down Arrow. Okay, now we've got  
16 it.

17 RW Beck joined this process to work with  
18 the staff probably in, I don't know, early to mid-  
19 March. And the role that we were given was to try  
20 to help staff, in essence as the bottom bullet  
21 down there on the page, to think outside the  
22 model. So traditionally what the gas unit staff  
23 has done in putting together its natural gas  
24 assessment is to really prepare a point forecast.

25 They recognize that that doesn't deal

1 with uncertainty. We've tried to give them in the  
2 work that we have done some ways of thinking about  
3 uncertainty to try to move away from a reference  
4 case where we say, this is our forecast, but  
5 instead staff puts a reference case on the table  
6 that all of you can use for thinking about how the  
7 world might work.

8 And the alternatives that we crafted and  
9 put forward to go alongside the staff forecasts  
10 are really designed to add more fuel to the fire  
11 for that thinking process about what could happen  
12 versus what will happen.

13 There are two things if you were going  
14 to ask me, what are the two key things that come  
15 out of staff's work. And what I would tell you is  
16 the two bottom-line, fundamental findings that  
17 ought to be uppermost in your mind are that you  
18 see a lot of LNG coming in to meet US demand. And  
19 the reason for that fundamentally in the model is  
20 the model is saying that it's economic for that to  
21 happen. That's really important to understand.

22 The second thing is that the basis  
23 differential to California, and to a degree the  
24 West, the Western base is narrow so it doesn't  
25 actually flip but the basis to California flips

1 completely. So that instead of California  
2 receiving a discount to Henry Hub prices we begin  
3 to pay a premium. And what you see in the rest of  
4 the West is that the basis differential narrows  
5 substantially.

6 So if you go back to the table that had  
7 a whole bunch of columns for different basis  
8 points and years that Bill Wood had in his  
9 presentation you see the negative basis out of the  
10 Rockies and the negative basis out of AECO narrows  
11 substantially relative to California. When you  
12 add transportation costs to that, by the time it  
13 gets to California we're going to pay a premium.  
14 Those two key things are really important.

15 Now Youssef had a lot of experience in  
16 modeling. I probably have a fair bit of  
17 experience, one could probably say over a 20 year  
18 period in the natural gas business in and out of  
19 models. And we were asked to make some comments  
20 about NARG and the World Gas Trade Model.

21 And, you know, there are things that  
22 have to be recognized kind of on both sides.  
23 There's a lot of things that the model does really  
24 well. Bill Wood talked about how it gets the  
25 basis differentials right. That's really

1 important to recognize.

2 The other thing is that it correctly, we  
3 think, accounts for the expected future shift in  
4 the physical elements of the market structure.

5 Then it takes demand and supply and it  
6 matches them up and it computes price where price  
7 is the rationer, the arbiter of the market in  
8 essence. It makes supply and demand equal. Where  
9 they are out of balance price rises so that demand  
10 exits the market and new supplies produce so that  
11 everything equilibrates. Those are important  
12 things to understand about the model.

13 But the way that the model has been  
14 used, for better or worse, is really to produce  
15 this point forecast that we've talked about. And  
16 so what we are trying to do is give folks some  
17 ways of thinking outside that point forecast.

18 Another point I can make about it is  
19 that means that it is really hard to run a lot of  
20 sensitivity analyses. Staff to date has run four.  
21 If you let some of us, me and the staff combined  
22 go wild with the kind of sensitivities that we'd  
23 love to be able to run, that number probably  
24 expands pretty quickly within probably five or ten  
25 minutes of discussion to 20 or 30. And I'm sure

1 that to assess a full range of uncertainty we'd be  
2 talking more than 100 different scenarios. And  
3 doing that is just not practical.

4 ASSOCIATE MEMBER GEESMAN: Let me ask,  
5 Catie. What's practical? Or how do you define  
6 practicality?

7 MS. ELDER: How much money do you want  
8 to spend to resolve the uncertainty?

9 ASSOCIATE MEMBER GEESMAN: I'm of the  
10 opinion we spend millions and millions and  
11 millions of dollars anyway. I don't know what we  
12 spend it on. I don't always know of what value it  
13 is. Why shouldn't we have modeling tools that  
14 lend themselves to running multiple scenarios  
15 rather than investing so much in building some  
16 kind of Maginot Line that provides us a single  
17 point.

18 MS. ELDER: That's a very good point.  
19 And I think that --

20 ASSOCIATE MEMBER GEESMAN: I'm not  
21 expecting a contractor to respond.

22 MS. ELDER: Right, right.

23 ASSOCIATE MEMBER GEESMAN: But certainly  
24 the staff people in the audience, I think it's  
25 something that bears quite a bit of thought. I

1 think it would be of greater value to state  
2 government to have more scenarios rather than  
3 fewer, even if there is a sacrifice in depth that  
4 goes along with that choice.

5 MS. ELDER: I suspect, Commissioner,  
6 there's a lot of folks in this room who'd agree  
7 with you. I think I do and I think a lot of --  
8 Leon is holding up his hand. And if Youssef could  
9 get a word in edgewise I'm sure he'd agree too.

10 DR. HEGAZY: Yes.

11 MS. ELDER: That was a yes.

12 Let's talk about demand a little bit.

13 The range of uncertainty, the way that we  
14 articulated the range of uncertainty around  
15 demand. We worked out two different approaches to  
16 try to help the Commission understand the range of  
17 potential variation in natural gas demand around  
18 the reference case.

19 The first one uses the variation in  
20 historical demand growth and creates a statistical  
21 distribution, standard deviation, around that  
22 historical demand growth. That would then do some  
23 Monte Carlo draws out of and create basically an  
24 expected case demand forecast and a 90th  
25 percentile case and a 10th percentile case. I'll

1 show you what those look like. They're rather  
2 astounding.

3 The second approach that we took, and  
4 this is delineated in detail on a subsequent page  
5 that I'll show you, it's also in the report, we  
6 listed the factors high, low or around, but above  
7 and below, that we thought would create higher  
8 versus lower demand. And you can change that  
9 list.

10 The real point of trying to take the  
11 quantitative approach versus the bottoms-up  
12 approach that is in the more detailed list of  
13 factors table is that we don't really know what  
14 might create, at the end of the day, higher or  
15 lower demand. We've got some ideas that might.

16 But by just taking the quantitative,  
17 statistical approach we don't have to worry about  
18 what those factors are. We can just say, hey  
19 look, we know that demand varies by a lot. And we  
20 can incorporate that into the demand forecast  
21 without having to worry about what it was that  
22 made demand higher or what it was that made demand  
23 lower.

24 The other thing that we did is that we  
25 benchmarked staff's demand forecast against EIA.

1 Now not because we thought EIA was right. That's  
2 not why we did it. We did it because it's  
3 obvious, it's out there, it's published, lots of  
4 people look at it to see what it is. A lot of  
5 people have it in mind as to what it is. It's  
6 easily available. So we'll show you our  
7 comparison of the staff's demand forecast versus  
8 what EIA's has got.

9 And I think that shows up in the next  
10 graph if I'm not mistaken. There you go, there it  
11 is. The black line is staff's NARG reference case  
12 and the other lines are all of EIA's demand  
13 forecasts. The blue one is EIA's reference case,  
14 the gray is their high, the magenta or pink color  
15 is their low.

16 Now if you go back a page, and this is  
17 my intent, to make sure that everybody is dizzy,  
18 is that you see the staff's demand forecast is  
19 really similar to EIA's in the first couple of  
20 years. There's not a lot of difference actually  
21 between EIA's high and low versus its reference  
22 case in the first couple years versus staff's  
23 case.

24 The real differences occur in those out  
25 years beginning by about 2011 on out through 2017.

1 You see that staff's demand case is about a  
2 trillion cubic feet higher. I'm sorry, two  
3 trillion cubic feet higher than EIA's. The reason  
4 for that, Dale talked about it earlier. He talked  
5 about the cap and trade elements and emissions  
6 limits, allowances that are captured in his  
7 electric demand model. That's why this demand  
8 forecast is so much higher than EIA's.

9 ASSOCIATE MEMBER GEESMAN: But even  
10 there I would say based on the discussion we had  
11 this morning you may very well be arbitrarily  
12 constraining that same dynamic in the Western  
13 United States where it might appear that  
14 California policy is driving the shift away from  
15 coal at an even more rapid rate than is likely to  
16 occur on the eastern coast.

17 MS. ELDER: That is absolutely right.  
18 There's a question about whether or not the  
19 demands that we have for the West is high enough  
20 at this point.

21 DR. HEGAZY: One thing we did in our own  
22 was to compare the EIA forecast for electric gas  
23 demand versus ours. Ours, that's RW Beck. What  
24 happened is EIA, they delivered their forecast  
25 probably early in 2006, maybe at the end of 2005,

1 and there were several factors that affected their  
2 outlook on the electricity demand for gas. One of  
3 them is the capital cost for coal, which at that  
4 time was a lot lower than what it is right now.

5 So when we ran our model the model did  
6 not take more than probably five, six percent off  
7 additional coal generation for the next 20 years  
8 in the entire United States. For EIA they  
9 expected around 55 percent of the new capacity  
10 additions to come from coal. Most of those were  
11 in WECC in the west and the southeastern part of  
12 the United States.

13 That is what we found that is the most  
14 dramatic change, the most dramatic difference  
15 between our assumption and their assumption. And  
16 I believe that the electric gas demand that came  
17 from the Commission also had the same assumption  
18 that we had.

19 MS. ELDER: And Youssef, when you  
20 mentioned coal cost you were talking about  
21 construction cost?

22 DR. HEGAZY: Right. The capital cost of  
23 adding a coal power plant. Over the last 18  
24 months they have increased from around \$1500 a  
25 kilowatt to \$2500 to \$2800 a kilowatt. So it's

1 almost doubled. That's a major factor in coal.  
2 And in addition to that the known fact that the  
3 regulation or legislation on CO2 production is  
4 lowering in the future.

5 MS. ELDER: And we should tell you that  
6 where those construction cost numbers come from,  
7 they're coming from our independent engineering  
8 colleagues who are working on coal-fired power  
9 plants. Right, Youssef?

10 DR. HEGAZY: Right. And actually also  
11 you can look at a lot of the IRPs, integrated  
12 resource planning, that has been filed by major  
13 IOUs around the country. You will see the same,  
14 the same figures in the most recent ones.

15 MS. ELDER: Okay. I mentioned earlier  
16 how Youssef actually constructed the demand case.  
17 In essence he thinks of demand as growing at some  
18 rate with an error term around it. So we've got  
19 the growth rate that comes from the model  
20 projection. And then what we used, we used  
21 historical demand and the rate of change of growth  
22 in historical demand to create this distribution  
23 or this disturbance term, this distribution that  
24 the disturbance term is drawn from via the Monte  
25 Carlo simulation. At some point I'll get the

1 words out of my mouth correctly.

2 We just wanted to make sure we had at  
3 least one equation in here to torture you with in  
4 Youssef's section since I've got a couple.

5 The results of that are what you see on  
6 this page. The blue and the black line that are  
7 in the middle there show you staff's expected  
8 demand forecast, also shows you the random draws,  
9 the expected case that comes out of our analysis  
10 around that. But then the gray line and the pink  
11 line are the ones that are interesting. Those are  
12 those 10th percentile and 90th percentile demand  
13 cases.

14 And what you see here, and this is sort  
15 of the critical thing to notice is that at the  
16 beginning of the forecast during 2007 the  
17 differences between those numbers were about half  
18 a trillion cubic feet a year. So two cases that  
19 capture kind of the biggest range of the universe  
20 around the expected case are roughly half a  
21 trillion cubic foot higher than and lower than the  
22 expected case.

23 By the time you get out to the end of  
24 the forecast period that gap or that range widens  
25 to be almost two trillion cubic feet. So we're

1 talking about a difference potentially when you  
2 think about the distribution that captures all of  
3 the uncertainty and demand. That demand could be  
4 two trillion cubic feet higher than we think or  
5 two trillion cubic feet lower than we think. And  
6 that's a huge, just a huge number.

7 ADVISOR JONES: Catie, while you've got  
8 that chart up. It shows more here than it did in  
9 the earlier graphs. The sort of blip up in demand  
10 between 2011 and 2013.

11 MS. ELDER: Right.

12 ADVISOR JONES: And you guys are  
13 investigating that or do you have a cause for  
14 that?

15 DR. HEGAZY: Let me just explain what  
16 that graph is because this is not a -- The demand  
17 growth is not our forecast.

18 ADVISOR JONES: Okay.

19 DR. HEGAZY: What we are trying to show  
20 here is, if you remember what one of the earlier  
21 slides that Mr. Fore has shown here in the morning  
22 in which he was talking about the elastic part of  
23 the core demand, in which demand is a function of  
24 gas prices and then population and then GDP and  
25 other factors like that.

1           Each one of those factors are random in  
2 nature. When you assume GDP is going to grow at  
3 three-and-a-half percent for the next 10 or 15  
4 years this is a very strong assumption. So what  
5 we are seeing here is over the history that three-  
6 and-a-half percent has a distribution around it.  
7 It was one year at five-and-a-half percent,  
8 another year it was one percent and maybe another  
9 year it was almost zero.

10           So including that distribution for  
11 population and distribution for GDP and for all  
12 other parameters in the right hand side of the  
13 demand equation is the way that we suggest to do  
14 in order to -- and running a Monte Carlo  
15 simulation on 100 cases for each, in order to come  
16 out with a probability distribution of how the  
17 growth of demand, say for the residential sector  
18 or industrial sector, should look like.

19           Now when you do that randomness there is  
20 two different ways. One is a simple Monte Carlo  
21 simulation and the other one is called, and bear  
22 with me with this name, is Latin Hypercube, in  
23 which you look at the distribution and divide it  
24 into areas. And you make sure that you're drawing  
25 consistently from the area that you think has

1 higher probability. You're drawing more from the  
2 area that has higher probability and you're  
3 drawing less from the area that has less  
4 probability. And that's what we did in the last  
5 run.

6 Before that when you just did a raw run  
7 of the case, one of the runs or two of the runs  
8 might come from the tail end of the distribution  
9 more than they should and they create that bump  
10 that you have seen there in your graph. I hope  
11 everybody is still with me.

12 MS. ELDER: We're all here with you,  
13 Youssef.

14 DR. HEGAZY: Okay. Did that answer your  
15 question?

16 ADVISOR JONES: That was fine, thank  
17 you.

18 MS. ELDER: It does partly but I think  
19 we need to go back and we need to look at whether  
20 or not there is a blip, an upward blip in demand  
21 in the reference, in staff's reference case number  
22 in 2012 or whether I mislabeled the lines.

23 Here is table that lists the different  
24 variables that could create a higher growth case  
25 for demand versus a lower growth case for demand.

1       You can see they revolve around things like  
2       efficiency policy, conservation policy, carbon  
3       reduction, which we've spent a little bit of time  
4       here talking about. The impact that that has on  
5       coal-fired generation.

6                 Demand could be lower, on the other  
7       hand, if folks decided that they wanted to build  
8       some nuclear power plants instead. The impact of  
9       renewables arguably should be to reduce natural  
10      gas demand. Natural gas demand might be higher  
11      with higher economic growths.

12                We mentioned hydroelectric conditions  
13      because we know that they have a big impact here  
14      in California, particularly in Northern California  
15      on the PG&E system. Although they should be  
16      temporary impacts, we would think, at least in the  
17      short term, unless we actually see the snowpack  
18      totally melt in the Sierra due to global warming.

19                And then electric transmission issues  
20      could have an impact on natural gas demand if we  
21      are constrained on capacity expansions. For  
22      example perhaps the Palo Verde Devers line that  
23      was denied last week by the Arizona Corporation  
24      Commission. Then perhaps that means we have to  
25      deny more electricities and natural gas here in

1 California, so all of those things could have an  
2 impact high and low.

3 And I'm sure many of you could add to  
4 this list on both sides what the high side and the  
5 low side --

6 ADVISOR JONES: Catie, in terms of the  
7 hydro conditions. If you go back to the supply  
8 that was forecast out of NARG you show Blythe to  
9 be zeroed out. So that means it is not being used  
10 at all for a three or four year period but then  
11 there's an assumption that it comes back on. In  
12 reality would a pipeline company keep that line  
13 available just betting that there might be some  
14 use down the road? And what does that do in the  
15 case of having low hydro conditions where you are  
16 much more dependent on gas?

17 MS. ELDER: That is a question that  
18 probably deserves more than a 30 second answer I'm  
19 going to give you. It's probably a four or five  
20 page long discussion. But let me talk on a couple  
21 of things to think about.

22 We actually have seen historically,  
23 within the last 15 years we have seen some pretty  
24 low flows on the El Paso system into California.  
25 And despite those low flows the pipeline did

1 remain in place and available so that when demand  
2 did increase we were able to get additional gas  
3 supply over that pipeline. Now what happens in  
4 the future is kind of a different question.

5           If in point of fact the impact one could  
6 imagine, I'm not saying that this is what the  
7 model projects or what the model results even  
8 show, but they sort of give you a glimmer of this  
9 idea. As Costa Azul begins to deliver gas some of  
10 that gas moves eastward on Baja Norte and then up  
11 towards Ehrenberg-Blythe then some of it could  
12 come into California. Some of it could ostensibly  
13 flow via displacement back to Phoenix. Perhaps El  
14 Paso decides to physically reverse the flow of its  
15 southern system so that gas can flow towards  
16 Phoenix. Any of those things are possibilities.

17           And I think it's really hard right now  
18 to predict which one of those would happen. But  
19 as you rightly point out, we need to keep them all  
20 in mind. So how is that for the quick answer?

21           ADVISOR JONES: That's great, thank you.

22           MS. ELDER: Recognize that it's a  
23 complicated story.

24           This is a picture. Mike gave you the  
25 picture earlier in his presentation, the color

1 picture, but I had this notion that I had to put  
2 everything in black and white for the report so I  
3 put everything in black and white. Or most  
4 everything at any rate. So this graph is trying  
5 to recapitulate what Mike Purcell told you about  
6 the supply forecast of the reference case.

7 And here is a really key thing that I  
8 wanted to use this to remind people of and that is  
9 just the massive, the massive increase in LNG that  
10 comes into the US in order to meet rising natural  
11 gas demand. You see the bottom of the bar is  
12 really domestic production and that number kind of  
13 bobbles, if you will, around 18-and-a-half, maybe  
14 17 trillion cubic feet a year depending on the  
15 year. And then we get some gas from Canada.

16 That number shrinks by a little bit you  
17 can tell. That's the diagonally colored part of  
18 the bar. And the space around that bar gets a  
19 little bit compacted over time. But the big  
20 change in the picture is how much LNG comes in to  
21 meet the rest of US demand.

22 I wanted to talk about what the  
23 uncertainties are around this supply forecast.  
24 First off Mike mentioned, and if you look in the  
25 detailed version of the preliminary report,

1       there's much more color around this issue than I  
2       am going to go into here.

3                But it seems pretty certain, pretty easy  
4       to demonstrate that there are increasing  
5       production costs. The cost of producing gas is  
6       increasing, significantly increasing and at the  
7       same time we've got declining production per well.

8                And I am going to show you in just a  
9       minute, or do show you in the detailed, the more  
10      detailed report, that that's not just total wells  
11      where production is declining but it's production  
12      per new well. Production for a new well that gets  
13      drilled, that production is declining for every  
14      new well that we drill. They produce less and  
15      less. And Mike talked about that.

16              He talked about why that's the case when  
17      he spoke but I'll give you some other ideas around  
18      that that sort of go beyond the notion that all  
19      the finds, the gas reservoirs that we're finding  
20      are tinier, and tinier and tinier so it's  
21      inevitable that we'll produce less. But I think  
22      there is a little bit more to it than that that's  
23      useful for us to keep in mind. And that has to do  
24      with the investment reward versus risk evaluation  
25      that producers make as they drill.

1                   Producers right now because of pressures  
2                   from Wall Street, because of the fact that it's  
3                   less risky with new technology, are able to focus  
4                   on in-fill drilling and drilling unconventional  
5                   reserves. Those unconventional reserves cost more  
6                   but they're less risky. So when you multiply risk  
7                   times costs they look more favorable than  
8                   conducting a lot of outright new exploration.

9                   And the other thing that we know, if you  
10                  spend a lot of time looking at this data, is that  
11                  we don't drill a lot of true exploration and  
12                  production wells, exploratory wells anymore. We  
13                  actually drill very few.

14                 So with all those things going on the  
15                 one thing to keep in the back of your minds that  
16                 this sort of blanket claim that, oh my goodness,  
17                 we can't ever produce more, probably to some  
18                 degree confuses cause with effect of what  
19                 producers are actually doing versus what they can  
20                 do.

21                 The second kind of key area of  
22                 uncertainty there with supply is we've mentioned  
23                 the areas that are closed to drilling. A lot of  
24                 people probably don't even realize that the Energy  
25                 Policy Act last year prohibited drilling under the

1 Great Lakes. And not only drilling for gas under  
2 the Great Lakes, there's a lot of gas in Michigan.  
3 Not only does it prohibit drilling under the Great  
4 Lakes but it says that you can't even drill a  
5 horizontal well from onshore underneath a lake.

6 We also had a ban adopted last year in  
7 Montana. No gas drilling on the front range of  
8 the Rockies in Montana. A senator from Wyoming  
9 just last week announced he is going to propose  
10 the same thing for Wyoming.

11 The Colorado Oil and Gas Conservation  
12 Commission is now having its makeup changed to try  
13 to make sure that it is not a group that favors  
14 producers but that it incorporates folks who are  
15 interested and support conservation as well as  
16 just production. So that it isn't for that agency  
17 to sort of encourage production but to actually  
18 encourage conservation of what we have to produce.

19 So there's some changes going on, for  
20 example, in the Rockies, as well as what happened  
21 with the Great Lakes that have an impact on what  
22 we can actually drill of that nearly 1100 Tcf  
23 resource base that we've got.

24 We had some questions earlier about how  
25 much Canadian gas was available to the US and

1       that's another big uncertainty. If you look in  
2       the more detailed report, I'm going to forget  
3       which graph it is, but there is a figure there  
4       that gives you some data on forecast production  
5       from Natural Resources Canada and then it also  
6       provides Natural Resources Canada's forecast of  
7       how much of that gas will get exported to the US.

8                 And the difference in the slopes of the  
9       two lines essentially represents what Natural  
10      Resources Canada thinks will get used to support  
11      tar sands production in Canada. And/or otherwise  
12      meet growing demand for natural gas in Canada.  
13      Which I think, if I remember correctly, is  
14      actually relatively small. So it is fairly safe  
15      to say actually that most of that is tar sands.

16                Now there are other folks who think that  
17      Alberta will decide to build nuclear power plants  
18      to provide steam for the tar sands production and  
19      that there won't be any increase in natural gas  
20      demand. So the real point is just to identify  
21      that there's a lot of uncertainty around what will  
22      really happen with how much natural gas gets used  
23      to support tar sands production.

24                And then the other point I want to make  
25      that is a key supply uncertainty, and I think

1 we've talked about this earlier in the day, is  
2 uncertainty about LNG access and costs. We talked  
3 about the geopolitical issues. You can convince  
4 yourself that perhaps there won't be as much LNG  
5 available as we think other times, so there's a  
6 lot of uncertainty around that.

7 I had forgotten that I included this  
8 table. I mentioned it earlier but let me, let me  
9 walk you through what this tells you. This is  
10 some data provided by Lippman Consulting. It's  
11 out of their supply model actually, we were able  
12 to use it with George's permission. Kevin  
13 Billings I think may have mentioned Lippman  
14 earlier.

15 This is recorded data on production, the  
16 number of wells drilled. And we can use that to  
17 calculate how many wells it takes to produce --  
18 And I just selected because it's a nice round  
19 number, 2.5, 20 cubic feet per year. So if you  
20 look at the column that says, Bcf is the label  
21 there. You can see that back in 1999 we were able  
22 to produce about .162 billion cubic feet for every  
23 new well we drilled. And last year the data  
24 suggest that that number was cut nearly in half,  
25 .091. Pretty dramatic change.

1                   Now the import that that has is this.  
2                   Back in 1999 with that kind of production per well  
3                   number you could drill 15,427 wells and produce  
4                   2.5 Tcf new production. Today it takes 27,414 new  
5                   wells to produce 2.5 Tcf of new production. So  
6                   that right there is the key sort of element behind  
7                   this notion that you have to keep drilling, you  
8                   have to keep drilling in increased quantity.

9                   This has nothing to do with depletion.  
10                  This has absolutely nothing to do with how much  
11                  gas we produced last year that we can't produce  
12                  this year because we already sucked the gas out of  
13                  the well. This is just identifying the fact that  
14                  for every new well we drill we're drilling wells  
15                  that produce less.

16                  ASSOCIATE MEMBER GEESMAN: What is going  
17                  on with rig count?

18                  MS. ELDER: The rig count actually keeps  
19                  climbing. I don't think I have that graph in my  
20                  hip pocket but I often have a graph handy that  
21                  will show you the rig count increasing and  
22                  sometimes I'll show it to folks even with the  
23                  number of wells drilled or production when cited.

24                  I think it's in the range, if I'm not  
25                  mistaken, right now about 1400 rigs drilling for

1 gas. And if I go back to about the year 2000  
2 there might have been a peak that was close to  
3 1,000. And then as prices dropped in 2001, 2002,  
4 2003 that fell off back down to about 750. Maybe  
5 700, 650. And then as prices rose again it's come  
6 back up and it's gone steadily up.

7 But the point that that brings us to is  
8 recognizing that if you're going to drill this  
9 many wells you have to have a lot of rigs, an  
10 increasing number of rigs, and you have to have a  
11 lot of people who know how to man them.

12 I mentioned sort of earlier this notion  
13 of cause versus effect. Mike had mentioned as  
14 well earlier that there were some reasons to think  
15 that maybe you could produce more gas.  
16 Essentially I would probably tell you if you gave  
17 me the right amount of vodka, or maybe if you  
18 don't even, that we can produce more gas.

19 Sure we can produce more gas out of that  
20 1100 trillion cubic feet resource base we've got,  
21 it's just a question of how much you want to pay  
22 to get it out. And what the model is telling you  
23 is that with the LNG cost that it's got in it that  
24 it is economic to use that LNG instead of to  
25 produce more gas.

1           So then having said all of that we built  
2           what I call a supply heuristic. And it's really a  
3           snapshot of supply at any given moment. It's  
4           pretty dang simplistic. But in essence it says  
5           that you can think of US supply as being comprised  
6           of last year's domestic production, subtract out  
7           what you'll lose due to depletion, add to that the  
8           production that you'll get from new wells,  
9           recognize how much gas you can import via  
10          pipeline, typically from Canada, add in LNG, and  
11          that's the US supply mix.

12                 Now I can add to that equation and  
13           rearrange it. Just move things to the other side  
14           of the equal sign with a modicum of algebra. And  
15           what you see is that I can understand the  
16           difference between US demand and US supply pretty  
17           quickly with this picture that I'm going to  
18           create. Basically demand minus supply is the gap,  
19           if you will, and you've got to figure out how to  
20           meet the gap. The gap could be met with LNG,  
21           arguably, or you can go back and try to adjust  
22           demand, reduce demand, or see if you can figure  
23           out how to increase supply. I mean, those are  
24           your fundamental choices.

25                 I think Dave Arthur from Redding today

1 asked a question that was kind of headed at that.  
2 If the issues or the variables that you've really  
3 got on the table are demand and supply, and LNG is  
4 a policy matter, which one do you try to  
5 manipulate or which one do you try to effect?

6 If you look at the preliminary report  
7 there's a set of tables in there that probably  
8 look far more confusing than they need to be.  
9 They are Tables 10 through 12 and they provide you  
10 with the detailed numbers behind these three  
11 cases. We did a reference case, a high supply  
12 case and a low supply case using this heuristic.  
13 The reference case just replicates what staff has  
14 gotten out of NARG. It just takes these  
15 variables, these simple variables that I talked  
16 about, depletion, the number of wells you drill  
17 and how much production you get per well, and  
18 basically takes our supply quantity and says,  
19 okay, if that's how much supply we can produce how  
20 do we do it. How many wells do we have to drill?  
21 What production per well do we get to do it. What  
22 kind of depletion there was. Just a quick  
23 snapshot way of thinking about supply.

24 You can see here in this table the  
25 listing of what the key assumptions were and the

1 gap, if you will, which in the model results is  
2 met with LNG, that we get from doing that. We  
3 have an aggregate depletion loss and we use this  
4 across all three cases of minus two percent. It  
5 turns out to be roughly equal to two, two-and-a-  
6 half trillion cubic feet a year.

7 But look here at the difference in the  
8 number of wells that end up having to be drilled  
9 by 2017. In the reference case we have 45,212.  
10 The high supply case is lower because we've got  
11 much more supply coming out of those. And in the  
12 low supply case I constrained that only 30,000.  
13 That 30,000 is roughly what we drilled last year.

14 In the production per well, both in the  
15 reference case and the high supply case I let  
16 those be the same at about minus four percent.  
17 Notice that the annual rate of decrease over the  
18 eight years that I had from the Lippman case was  
19 higher, it was almost 7 percent. I didn't have  
20 the guts, if you will, to actually set that four  
21 percent at minus seven percent.

22 And then we have the number, the  
23 percentage here on the rate of decrease in the  
24 amount of gas that we can get from Canada. All  
25 told the reference case gap between supply and

1 demand is about seven trillion cubic feet per year  
2 just for the US. It's not North America, this is  
3 just the US.

4 In the high supply case, which actually  
5 pretty closely mimics EIA's reference case, that  
6 gap ends up being about 3.3 trillion cubic feet a  
7 year. And in the low supply case, where you can  
8 see what the key changes are that we made there.  
9 All we did between the high supply case and the  
10 low supply case was change the number of wells,  
11 reduce the number of wells drilled by about 5,000  
12 per year. We let production pretty well actually  
13 settle out at zero.

14 And I'm looking at this and going, but  
15 those numbers are reversed. The low supply  
16 production per well should be minus four percent  
17 and the high should be zero. And that is a typo  
18 that is entirely my fault. It makes this very  
19 confusion. So my apologies for that.

20 The other key difference there is the  
21 change in Canadian imports. And those minor  
22 changes create a change in the high supply case  
23 versus the low supply case of almost six trillion  
24 cubic feet per year. Actually almost seven  
25 trillion cubic feet per year.

1           So the real point is, just some very  
2           minor changes in how you think the industry works  
3           have a really big impact on the total supply that  
4           gets produced. US domestic production. And that  
5           then has large implications for the amount of  
6           supply that has to be made up with LNG.

7           Now somebody else I heard ask, and it  
8           might have been Kevin Billings so I think he's  
9           probably left already to catch his airplane. Can  
10          we even get that much LNG? If you are really  
11          saying that we need in the EIA case -- EIA says we  
12          probably will end up using about 3, 3.5, 3.4  
13          trillion cubic feet per year of LNG.

14          We've got a reference case here using  
15          our staff assumptions out of the NARG model that  
16          shows seven trillion cubic feet. And then my  
17          draconian low supply case increases that number by  
18          another three up to ten trillion cubic feet. Can  
19          we even get that much LNG?

20          And that's sort of in some respects what  
21          Jim Jensen was talking about this morning. He  
22          talks about his total world LNG supply being about  
23          15 trillion cubic feet per year. So if staff's  
24          case is seven coming to the US then that is  
25          roughly half of the world's supply of LNG coming

1 to the US. And I actually don't know and we could  
2 ask Dale later, but I actually don't know what his  
3 world gas trade model has got in there as total  
4 LNG supply. That amounts to roughly half as I  
5 mentioned.

6 Now when you talk about the other --  
7 There's another graph in Jim Jensen's study that  
8 says, it talks about demand for LNG. What he is  
9 doing in that is essentially taking his 15  
10 trillion cubic feet of supply and he's saying, now  
11 which countries is it going to go to?

12 And he shows a much smaller number,  
13 about 4.4 trillion cubic feet by 2015 coming to  
14 the US, than staff has got. Staff's is 7, Jensen  
15 is about 4.4. So while the staff reference case  
16 is well within the total amount of LNG that Jim  
17 Jensen says is available in the world he would  
18 have probably only about 30 percent of that  
19 actually come to the US.

20 Now we could actually take this  
21 heuristic that we develop, these tables that are  
22 in Tables 10, 11 and 12. We could actually take  
23 that. We could constrain LNG in that table and we  
24 could tell you what kind of production numbers.  
25 How many wells you've got to drill and what

1 production has got to be in order to produce  
2 enough gas, if you will, to make up for what we  
3 lost in LNG.

4 It won't tell you anything about the  
5 economics of doing that but it will tell you what  
6 the production business ends up having to look  
7 like. And we'll give you a sense of how, whether  
8 or not you believe or you can make yourself  
9 believe that that could actually happen.

10 The other key piece of work that we did,  
11 and Youssef may interrupt me at any moment yet  
12 again. The other piece of work that RW Beck did  
13 had to do with oil prices and the relation of  
14 natural gas and oil prices.

15 And when Dale said this morning that he  
16 wants everybody to hold up their hand and repeat  
17 after me, natural gas prices are not related to  
18 oil prices, I wanted to stand up and cheer.  
19 Because I tell people that all the time. And then  
20 I go, but having said that, maybe it's a little  
21 more complicated than that. But I like to believe  
22 that and I like to say that. Then I step back and  
23 I realize, well, there are some linkages between  
24 the two.

25 Let me tell you a little bit about some

1 of those linkages. They really happen because  
2 higher, you have a lot of natural gas that's  
3 produced in association with oil. Higher oil  
4 prices increase oil production but then that  
5 associated amount will also increase. So if you  
6 increase oil production due to higher oil prices  
7 you probably get higher natural gas production.

8 You also will see the E&P budgets of a  
9 lot of different oil companies increase with oil  
10 prices. So oil prices go up, their earnings  
11 increase, they realize that they can plow more of  
12 their earnings back into the oil paths, they do  
13 more drilling. And so they spend that on more  
14 capital, capital projects.

15 It's also the case, I think folks have  
16 mentioned this earlier, that you had LNG contracts  
17 particularly in the Pacific market that were  
18 indexed to oil prices. In large measure that may  
19 have happened because there was a lot to use and  
20 because that gas actually displaced oil.

21 There are at least -- a number of folks  
22 who have suggested or at least I've heard suggest  
23 who were involved in some of those negotiations  
24 delivering LNG to Japan that that may not be,  
25 always be true. That there may be some -- I'm

1       trying to think of the right word.  Some change in  
2       the pressing mechanism of some of those contracts,  
3       or at least an openness to discussing them.

4                But also realize that the contract, for  
5       example -- in particular the contract to export US  
6       natural gas produced in the Cook Inlet of Alaska  
7       that goes to Tokyo Electric has been in place for  
8       40 years.  And my understanding from some of the  
9       folks at Marathon Oil, who sell that gas to Tokyo  
10      Electric, is that you don't just walk in and tell  
11      the Japanese that you want to link the price to a  
12      natural gas price rather than use the Japanese  
13      Crude Cocktail that has been constructed over the  
14      years, even though there might some willingness to  
15      move in that direction.

16               There are also some competitive links  
17      between oil and gas.  There have been competitive  
18      substitutes, primarily in the EG sector, to some  
19      degree in the industrial.  And you'll find a lot  
20      of people around who think that because that used  
21      to be the case -- You know, I can even remember  
22      when there were PG&E power plants that were  
23      switched to oil.  And I remember the phone call in  
24      which El Paso was told, the power plants will stay  
25      on oil until you drop your price.

1                   Can't do that anymore. So a lot of the  
2                   notion that oil and gas prices are linked really I  
3                   think has to do with this legacy of folks who  
4                   remember that you used to be able to switch gas  
5                   for oil. And they just don't quite realize that  
6                   you can't do it anymore.

7                   Some numbers. These are natural gas and  
8                   equivalent oil prices. There are nominal dollars  
9                   per MMBtu. What you're looking at is the price at  
10                  Henry Hub, which is the pinky kind of price and  
11                  the blue kind of price is a crude oil price.

12                  And what you can see when you look at  
13                  those, you know, having said that there's some  
14                  reasons why on the E&P side, there's some reasons  
15                  on the capital investment side that they might be  
16                  linked, then you look at the graph. And you can  
17                  see really key periods here where there's just no  
18                  relationship whatsoever.

19                  In large measure that is -- I shouldn't  
20                  say in large measure but to some degree that's  
21                  what Dale was talking about this morning. That  
22                  there is certainly no notion that just because  
23                  there are six MMBtus in a barrel of oil that the  
24                  way you forecast natural gas prices is to take the  
25                  oil price and divide it by six.

1                   And I've had people say that to me.  
2           I've had people say to me, Catie, why is your  
3           forecast so low? Oil prices are at 60. Divided  
4           by 6 the gas price should be 10. People say that  
5           all the time. But it's just wrong.

6                   Here what you see in particular is you  
7           can see a period in the late '90s, 1995 through  
8           1998 or so, where gas kind of bobbles along on its  
9           own. There is no real relationship to oil prices.  
10          Then you can see a period where they kind of move  
11          together then you can see another period where  
12          they don't.

13                  You can see spikes here, particularly in  
14          winter. In late 2000 or early 2001, again in  
15          2003. Again right after Hurricane Katrina where  
16          natural gas prices spiked far above oil prices.  
17          And in the post-Katrina environment we have  
18          natural gas prices far below oil prices. Now let  
19          me go to the next graph.

20                  I put more colors on it to make sure  
21          that you were totally confused. The green price  
22          here is natural gas. And we added to this resid  
23          and distillate because the other argument that we  
24          hear quite often are people who will say, natural  
25          gas will trade in a range relative to oil where

1 the boundary on the top is set by distillate and  
2 the boundary on the bottom is set by resid. And  
3 what you can tell looking at this graph is that  
4 ain't true either.

5 You can see that natural gas really  
6 trades above distillate. There is only point at  
7 which it trades above distillate. But when you  
8 look at the resid price you often see here natural  
9 gas trading below that resid price. And by the  
10 way, the resid price tracks crude really closely.  
11 And that makes a lot of sense because resid is not  
12 that different from crude, whereas distillate is.

13 And the question that I would ask, I  
14 don't know the answer to it but since I'm a  
15 consultant I get to ask questions that I can't  
16 answer, what you see is that the gap between  
17 distillate and resid -- here I could use the  
18 pointer if I knew how to turn it on. I got it.

19 See this gap here between crude, crude  
20 down here, crude and resid down here and  
21 distillate up here. So how it gets bigger? It's  
22 relatively constant for a really long period of  
23 time. For like '03 versus 1995. Through that  
24 period if you graphed a delta between those it's  
25 pretty much a constant. But beginning around the

1 middle of '03 on to the end of the period that gap  
2 widens. My guess is it's refinery capacity but I  
3 don't know that for sure.

4 So the bottom line that I need to  
5 articulate before I switch to the next page, I get  
6 in a hurry and ahead of myself here, is that the  
7 relationship -- there is a relationship between  
8 oil and gas. As much as we like to say that there  
9 isn't there is a slight relationship between the  
10 two. I think the words Dale used this morning is  
11 that they're correlated but one doesn't drive the  
12 other. The relationship is not a constant. And  
13 that's probably the big take-away here is that the  
14 relationship is not a constant, it's not simple.  
15 It's actually quite complex and it's hard to  
16 explain.

17 DR. HEGAZY: One thing that we have to  
18 realize, and it's from different academic and  
19 industrial studies that have been done in this  
20 area, is gas has a phenomena to phenomena that  
21 does not quite affect oil as much. One is the  
22 seasonality and the other one is the storage. The  
23 storage has a tremendous impact on gas prices and  
24 on the gas industry.

25 Since we're modeling here on an annual

1 basis the two of them are not captured. In other  
2 words, if we are to do a monthly modeling of  
3 natural gas prices and natural gas supply and  
4 demand, a little bit of link between oil and gas  
5 might, might exist.

6 As a matter of fact some very recent  
7 study has been done by the Rice University Energy  
8 Center, which I think Mr. Medlock works there, has  
9 shown that on a monthly basis, and if you account  
10 for seasonality and if you account correctly for  
11 storage, you will see some lags around two or  
12 three months between oil prices and gas prices.  
13 But not as strong as people might think.

14 MS. ELDER: Youssef has actually done  
15 kind of a literature review on this subject  
16 looking at a number of different academic studies.  
17 There is a very short summary of that work in this  
18 preliminary report that has been published so far  
19 and there is a longer discussion that he has  
20 prepared that we would expect would go into the  
21 long version of the report when that is released.

22 Let's talk about the price results. It  
23 would not be correct to say that RW Beck has  
24 somehow validated staff's forecast. We haven't  
25 done that.

1                   What we have really done is we worked  
2                   alongside staff asking questions, poking Leon in  
3                   particular because we all like to pick on Leon.  
4                   And he dishes it back too as we all know so it's a  
5                   good thing. So we have asked questions, we've  
6                   probed, we've made suggestions. We've said, have  
7                   you looked at how this result compares with EIA's  
8                   forecast, for example. So we've done some  
9                   benchmarking.

10                   But I have to tell you that RW Beck may  
11                   produce a gas price forecast that is different or  
12                   the same from this forecast. And I can't even  
13                   tell you if it would be different or the same.  
14                   But we did do that for a number of clients and it  
15                   may well be different than this forecast.

16                   We have looked at EIA's most recent  
17                   annual energy outlook, which we've mentioned  
18                   earlier, and I think it's figure 38 in the  
19                   preliminary report. And if flip the page here it  
20                   will show you, this is figure 38 from your longer  
21                   report. Bill Wood mentioned earlier that I would  
22                   show this to all of you.

23                   This is a comparison or a behchmark, if  
24                   you will, of staff's reference case out of its  
25                   NARG modeling effort against what EIA put out in

1 its annual energy outlook in February. And then  
2 there's another, the pink line is a price forecast  
3 that is prepared for another set of work that the  
4 Commission has underway. It's part of the IEPR.

5 It's the scenarios project where the  
6 gas, some electric production cost modeling is  
7 being done by Global Energy. And they also then  
8 have the ability to take that projection and plug  
9 it back into their gas price model and produce a  
10 gas price forecast.

11 They took their fall reference case,  
12 their fall 2006 reference case, plugged in -- and  
13 I'm giving you the short version of what they did.  
14 Plugged in EIA's oil price forecast and the pink  
15 line that you see here is the result. So they by  
16 plugging in EIA's oil prices were able to make  
17 their reference case match EIA relatively closely.

18 Now the black line here is staff's  
19 reference case. And what we see here is that  
20 after about the first five years, '07 through  
21 2011, after that the three price streams are  
22 pretty close. You see the seesaw effect that we  
23 talked about earlier a little bit in staff's case  
24 but by and large the range of the numbers is  
25 relatively close.

1                   Now the other thing that we plotted on  
2 here, not because we believe this is a good idea  
3 but because everybody does it, is we have plotted  
4 NYMEX futures prices. These were gathered at the  
5 end of April and I think in the middle of March if  
6 I'm not mistaken. And Youssef will correct if I  
7 got that wrong. Just to show you how close. We  
8 know that Global's forecast actually is adjusted  
9 for NYMEX, explicitly just for NYMEX in the first  
10 24 months and then I believe the second 24 months  
11 they have a mean reversion process that converts  
12 that forecast back to their fundamental case.

13                   And we don't exactly know what EIA does  
14 in the early years but we believe that if they  
15 could tell us what they really do we'd be  
16 fascinated by it. What we know is that they won't  
17 tell us what they really do.

18                   We also -- One of the benefits that  
19 comes out of the annual energy outlook is that EIA  
20 will publish a comparison of their forecast to a  
21 whole slew of other forecasts. They graph energy  
22 ventures analysis, and EEA, SEER as well as some  
23 other work that Altos has done. And they provide  
24 a table that's buried in the back pages of the  
25 outlook that compares all these different

1 forecasts.

2 We went and grabbed those and we plotted  
3 those, the prices for 2015 and the prices for  
4 2025, which are the ones that were easily  
5 obtainable out of that table back at the end of  
6 the energy outlook. So the light bluish kind of  
7 column is 2015 and the one with the diagonals in  
8 it is 2025.

9 And what you see here is that when you  
10 get into those out years staff's reference case,  
11 or their preliminary results at any rate, are  
12 actually, particularly out in the out years,  
13 pretty high relative to everybody else. And at  
14 2015 which is the end, close to the end of our  
15 reference period of 2017, that number is not a lot  
16 different than several of these others. So, you  
17 know, when you look at what the staff has done  
18 relative to what other folks have said out there,  
19 it's pretty close.

20 And I think Herb's graph from SoCal  
21 provided their forecast and had a comparison of  
22 staff's number to SoCal's forecast and I think  
23 that we could probably incorporate that as well.

24 By way of summary, if we talk about the  
25 variables that might create higher versus lower

1 natural gas prices, this is the list of variables  
2 that we've developed. Sort of putting everything  
3 all together. We've got some that are policy-  
4 related or policy-driven that we've talked about  
5 before here. We've got the demand variables.  
6 Demand side variables that have a big impact. And  
7 then the supply and infrastructure-related  
8 variables that we've really talked about in that  
9 supply, that are behind that supply heuristic, if  
10 you will. Conceptually behind that supply  
11 heuristic.

12 Now the other part of what we do,  
13 particularly when we're picking on Leon, and he's  
14 going to get me for this, is we have really kind  
15 of taken responsibility for trying to create, you  
16 might call it a punch list or a checklist, a to-do  
17 list. But this is a list of things that we have  
18 noticed as we've talked to the staff and we've  
19 looked at the results that are kind of the key  
20 questions in our minds.

21 But we think that as you move from this  
22 draft case or this draft reference case,  
23 preliminary reference case, as you move after this  
24 workshop to really finalize this case, that these  
25 are the things that need a second look or some

1 time spent on them to talk about.

2 One of them would be the LNG  
3 assumptions. We mentioned that before, I don't  
4 need to say a lot more about that.

5 We're aware now that the model has got a  
6 huge increase in demand for gas in the eastern US  
7 due to carbon regulation or emissions treatment  
8 and so forth. We need to understand and be really  
9 comfortable with that number. And we also need to  
10 think about what the implications of that could be  
11 for the WECC that we haven't captured. Some of  
12 that may be captured in the scenarios project, by  
13 the way.

14 Mike Purcell and I might be slightly  
15 confused about how the Rockies land access  
16 restrictions are treated. There are some that are  
17 in the model, we think there are some others that  
18 are not in the model that probably ought to be in  
19 the model. But somebody has got to go sit down  
20 and take a look at that and make sure of what  
21 we've actually done. What's actually in there and  
22 what actually ought to be in there.

23 We think we have not spent enough time  
24 looking at the results for the impacts on the  
25 Pacific Northwest and Northern California. And I

1 think the reason that kind of happens naturally is  
2 that when you look at the model results all the  
3 action is kind of in Southern California. You've  
4 got Costa Azul coming on and delivering lots of  
5 gas. That backs out some Southwest gas out of El  
6 Paso's southern system. That sort of, you know,  
7 thing is going on.

8 And you look at the Northern California  
9 results and the flows don't seem to have changed a  
10 lot. But it would be worth it to sit down and  
11 look at not only, I think as somebody mentioned  
12 earlier today, actually calculating the capacity  
13 factors on the system but just taking a look at  
14 what changes and make sure that we're really  
15 comfortable with that.

16 We also need to take another look, I  
17 think, at the impact of dry hydroelectric  
18 conditions. The models and virtually everybody  
19 who does this knows that this is how we all do it  
20 but we all assume average or normal hydro. That's  
21 the expected case. But we need to -- As 2001  
22 showed, we need to worry about what happens in a  
23 dry hydro case.

24 There are potentially some impact of  
25 some other policy scenarios that would come out of

1 the integration of these results with the modeling  
2 results coming out of the scenarios project. So  
3 we have to be cognizant of how those things fit  
4 together or figure out how they fit together and  
5 be cognizant of them.

6 We also thought it was potentially the  
7 case that even while there is not a lot of  
8 substitution for gas versus oil here in the US  
9 anymore for a lot of reasons that arguably there  
10 may be some substitutability globally and we're  
11 not exactly sure that we understand how the model  
12 treats that. So that's something that is probably  
13 worth at least some time discussing further and  
14 making sure that we understand it well.

15 Now the last thing that is on my list  
16 here. And this may go to the question that  
17 Commissioner Geesman answered earlier about  
18 modeling tools and scenarios that actually capture  
19 uncertainty. The use that staff is making of the  
20 NARG model we understand there are some ways that  
21 you could actually use NARG probablistically. And  
22 those need further explanation. Explanation, they  
23 need further exploration. It was an E word, I  
24 just couldn't say the right E word.

25 We would recommend spending some more

1 time to understand how staff could use NARG  
2 probablistically to come at some of these issues  
3 rather than take the very broad brush approach  
4 that we have put to work here, which is to say,  
5 demand could be higher or lower by this much.  
6 Supply could be higher or lower than this much.  
7 These are the issues that you need to worry about.  
8 But you probably can use the existing modeling  
9 tool in a much more robust way.

10 That's our sense. But again, we're not,  
11 we will not -- Youssef and I will not claim to be  
12 NARG expert users but we do understand there's  
13 some capability there that is not being exploited  
14 fully at this time.

15 And with that, that's all. Questions?  
16 Nobody looks like they're asleep. George, right?

17 MR. CLAVIER: That's right, very good.  
18 I'm George Clavier with PG&E. And the question I  
19 had probably is better addressed to staff as  
20 opposed to Catie.

21 But I noticed in the sensitivities  
22 chapter in the report you ran sensitivities  
23 regarding adding additional LNG supplies into  
24 Costa Azul. And you reported the quantitative  
25 effect on flows but I didn't see any price

1 effects. So my question is, do you intend to  
2 report those out in the future? I guess that's my  
3 question.

4 MR. BRATHWAITE: Yes we did do the four  
5 sensitivities. These sensitivities we are still  
6 trying to work on them. Before we finalize them  
7 we do not want to put out the exact results that  
8 we got out of the model. Now some of the results  
9 that we have so far are somewhat, shall we say,  
10 within the precision of the model and we want to  
11 discuss that internally a little bit before we put  
12 the results on the street, so to speak. We are at  
13 the interim process, shall we say, before we  
14 finalize those products, yes.

15 MR. CLAVIER: But your intent is in the  
16 final report those sensitivities will be released?

17 MR. BRATHWAITE: In consultation with  
18 the IEPR committee and the Natural Gas Committee.  
19 It is our intent, yes, to do so.

20 MR. CLAVIER: Okay, thank you.

21 MR. BRATHWAITE: Sure.

22 MS. ELDER: Yeah.

23 MR. COWDEN: Bob Cowden, PG&E. This is  
24 a follow-up question to George's. I think it's  
25 back to Leon. On those sensitivities in the

1 report you talked about the Oregon LNG case not  
2 having any price benefits to California. And I  
3 guess, I think that's a function of how you  
4 modeled the Oregon LNG case. Where you just put  
5 those supplies into the Pacific Northwest demand.

6 I think if you created another  
7 sensitivity or you modeled a Southern Oregon LNG  
8 project that I guess delivered those supplies  
9 directly to Malin, I think you'd find that there  
10 were price benefits to California in that type of  
11 case. How you model an Oregon LNG project kind of  
12 is dependant on where it is, whether it's in  
13 Northern Oregon or in Southern Oregon.

14 So I don't know if you were planning on  
15 doing that in any more work you were looking at.

16 MR. BRATHWAITE: Well, I mean, I cannot  
17 definitively tell you that we are planning to do  
18 any more work in terms of doing the slight  
19 restructuring that you are suggesting. But it is  
20 certainly something that we'll take into  
21 consideration because I think you are absolutely  
22 correct. The architecture that we have in the  
23 model up in the Pacific Northwest will certainly  
24 affect whether we see the price effects that may  
25 be possible if more LNG is inserted into the

1 Pacific Northwest.

2 MR. COWDEN: Or if you deliver it  
3 directly to Malin.

4 MR. BRATHWAITE: If delivered to there,  
5 yes, yes.

6 MR. COWDEN: Okay, thanks.

7 MR. BRATHWAITE: Most certainly yes.

8 MS. ELDER: Dale.

9 DR. NESBITT: Two questions, Dale  
10 Nesbitt, Altos, that Melissa asked that are great  
11 questions and require just a little bit of  
12 attention. Number one, why the bump in 2013 in  
13 the staff work. That's a really important  
14 question. That's when the carbon legislation  
15 starts by assumption. So what we said in the  
16 model was, we have a \$7 a ton carbon tax starting  
17 in 2013. That was our attempt to stimulate a  
18 Binghamon style, I call it tepid because it's not  
19 an extreme.

20 Now that's very interesting. What does  
21 that do? Suppose you didn't have it. Well we  
22 don't build new plants for awhile, we just go to  
23 worse and worse heat rates at the margin, okay.  
24 And then sooner or later you've got to start  
25 building new capacity. As soon as you pop a \$7

1 carbon tax it accelerates the build rate and you  
2 saw that curve flatten. It was a great question.  
3 Alternative carbon scenarios are going to give you  
4 alternative gas burn growth rates and it is quite  
5 sensitive to that.

6 The second really good question had to  
7 do with pipelines and reserves and that kind of  
8 thing. One of the things that staff had intended  
9 to do this year, we never got around to it, was to  
10 use the short-term model that you've never used.  
11 It's monthly, going forward ten years. And one of  
12 the issues with regard to pipeline retirements  
13 really isn't annual load, which you focused on  
14 pretty much completely today, it's monthly load.

15 So your point is exactly right. They  
16 don't retire these pipelines because if in one  
17 month out of three years they're going to carry a  
18 critical load those pipelines will stay in  
19 service. People will maintain their firm  
20 transportation requirements on those pipelines to  
21 hedge against that. That's really the reason in  
22 the real world, you know.

23 You'll see power plants in cold standby  
24 and various stages of cold standby by analogy.  
25 Because just as everybody said, even in a -- one

1 thing we know is that we're going to have  
2 volatility and variability in load. And so in the  
3 model that has been used to date by staff, the  
4 long-term model which averages out or annualizes  
5 these effects you're not going to capture those  
6 critical issues. But in the short term model,  
7 that I don't know what the future of it is, it  
8 picks those right up.

9 A classic example of that we've seen in  
10 the last two years across the Atlantic Basin. We  
11 have seen LNG cargoes come to the US 10 to 11  
12 months of the year and go to the UK and Zeebrugge  
13 for one month. Well if you model that on an  
14 annual average basis you'd be pretty naive,  
15 overstated for emphasis. So those are good  
16 questions.

17 One other thing about oil that's worth  
18 characterizing, and I've done quite a bit of  
19 refining modeling in recent months, in part for  
20 the Commission. Storage matters. People do store  
21 product, a lot of storage. But most important,  
22 what's going on in the world refinery sector,  
23 Catie was right on it, is that the cracking  
24 margin, which is the difference between the heavy  
25 products and the light margins, has gone to

1 infinity minus a little bit.

2 And so everybody has retrofit their  
3 refineries, which means there is no residual oil  
4 produced, overstated for emphasis, in the  
5 Rotterdam market, that's all of Europe, or in any  
6 of the North American markets. That's what's  
7 broken, the link. More and more. And Catie is  
8 quite right, it's not a complete break, but the  
9 link is breaking between residual oil -- it's  
10 always been broken between the high-end refined  
11 products and natural gas.

12 So I hope that helps on the pipeline  
13 reserve. Pipelines are held as reserve capacity,  
14 we know that, by people who want to hedge against  
15 dry hydro, a hot summer, that kind of thing.  
16 That's why they stay alive.

17 MR. TAVARES: Okay, any more questions,  
18 comments?

19 MR. PAK: Are you asking for questions  
20 to end the day or just on this presentation?

21 MR. TAVARES: Well, to end the day. I  
22 mean, go ahead.

23 MR. PAK: I'm glad you stuck around,  
24 Commissioner, because this is really going to be  
25 directed at you. We have offered to the staff

1 that we're going to provide comments on June 15,  
2 written comments, and we're basically going to  
3 provide them with our data sets with respect to  
4 supply that we believe will be reliably coming out  
5 of three different areas, California production,  
6 San Juan Basin production and Western Canadian  
7 production.

8 We believe that the staff data sets are  
9 far too optimistic for supply coming from those  
10 areas to California so we're going to provide you  
11 with our updated internal, homegrown forecasts  
12 that are based on our own review of data at the  
13 production sites as well as our own experience in  
14 having invested in some of the wells in some of  
15 those areas. Just to give -- And we're hoping  
16 that the staff uses them as part of their scenario  
17 analyses.

18 And just to give you some of the bona  
19 fides of our forecasts, those are the ones that we  
20 began developing pre-2000 and that has to date  
21 resulted in Sempra's commitment to invest over \$3  
22 billion in the development of infrastructure to  
23 build, to bring LNG to the United States and into  
24 California particularly. That's \$3 billion of  
25 private, at-risk capital that has no guarantee of

1 cost recovery other than through private contract  
2 and our operation and delivery.

3 We spent a lot of time in rooms with  
4 companies whose earnings, where if you compare  
5 earnings our earnings are about one day in their  
6 annual view. Their market caps are sometimes  
7 three to two hundred times ours. So if you think  
8 about a company our size investing in this  
9 industry it will give you an idea of the  
10 confidence that we have to hold our own and I  
11 think we have.

12 I think the bottom line, if you look at  
13 the Jensen report, and we'd love to see more of  
14 the information that he was relying on, we would  
15 basically agree that investment in any portion of  
16 the LNG supply and delivery chain, it is not for  
17 the faint-hearted. It is not for those whose  
18 views are formed by short-term perturbations and  
19 any portion or segment of that market or the  
20 collateral markets and ancillary markets that it  
21 affects or are affected by it.

22 It is not for the uninformed. So we  
23 hope that with those bona fides you understand  
24 that we believe in these forecasts. We think the  
25 state of California should take notice of them.

1 We certainly have invested a considerable amount  
2 of capital on at-risk basis based on these  
3 forecasts.

4 The other point that I would want to  
5 make, and maybe this is a follow-up to one of the  
6 earlier political scenarios that we had suggested  
7 that the staff, that they run. And that had to do  
8 with the South Coast Air Quality Management  
9 District's proposed air quality standard.

10 I can't believe we have gone through the  
11 whole day without talking about Senate Bill 412  
12 and the potential impacts that bill could have on  
13 gas supply here in California. You may know that  
14 that bill would require this Commission by the end  
15 of 2008 to perform a needs assessment for LNG.

16 We believe that you should take this  
17 opportunity in this Integrated Energy Policy  
18 Report to basically do that and address the issue  
19 of whether California, it's utilities or any other  
20 parties here should be going long on LNG. Sempra  
21 certainly has taken that position.

22 The Federal Electricity Commission in  
23 Mexico has taken a long position in the supplies  
24 coming out of Costa Azul. And we think it's a  
25 good time for the state to take a look at the

1 issue of whether you should be taking a long  
2 position, either with respect to capacity or  
3 supply, represented by LNG supplies.

4 We're obviously very bullish and we'd  
5 love nothing better than to have our forecasters  
6 and our planners sit down with you and your staff  
7 as you develop this Energy Policy Report to get a  
8 jump on SB 412 as well as to deliver what we think  
9 can be a very important IEPR to the state at the  
10 end of this year.

11 So I just wanted to let you know that we  
12 are going to be filing written comments next week  
13 on these topics and we hope that we can work with  
14 the staff to develop at least one of the outlier  
15 scenarios for supply to California.

16 ASSOCIATE MEMBER GEESMAN: I appreciate  
17 your comments, Al. Let me ask, are there supply  
18 basins where you feel that the staff's assumptions  
19 have been too pessimistic?

20 MR. PAK: We have not. I think that  
21 when we first came up here for the 2003 IEPR our  
22 analysts, one of our analysts was characterized by  
23 your staff as Dr. Doom because his supply forecast  
24 was pretty pessimistic across the board relative  
25 to all of the information that you were looking

1 at. Our information across the board continues to  
2 be more pessimistic.

3 There are things that we haven't, we  
4 don't reflect in our forecast. Things like, is  
5 there going to be a next breakthrough technology  
6 development in oil drilling, well drilling,  
7 recovery of natural gas from deep supplies. We  
8 just don't foresee that happening in the time  
9 frames necessary to out-compete for contestable  
10 markets against LNG supplies that we're certain  
11 will be here beginning in the first quarter of  
12 2008.

13 ASSOCIATE MEMBER GEESMAN: Do you  
14 envision having competition from other LNG  
15 terminals on the West Coast?

16 MR. PAK: It is our official position  
17 that we don't comment on other terminals here in  
18 the state but we have always thought that there  
19 was room for more LNG to be imported than is, than  
20 could be imported through the first phase of the  
21 Costa Azul project. That's why we have spent a  
22 lot of money and time pre-constructing for an  
23 expansion of roughly 1.5 Bcf per day.

24 We believe that we are positioned to  
25 compete against any terminal that might be built

1 on the West Coast. If they are more competitive,  
2 if they have supply in the chain that would out-  
3 compete us then we might not build the expansion.  
4 But based on the shipper response to our open  
5 season that we held last year we think we're  
6 competitively positioned. If there is another  
7 terminal we'll have to relook at that based on the  
8 shipper response to it.

9 ASSOCIATE MEMBER GEESMAN: Thank you.

10 MR. TAVARES: Next steps. Any more  
11 comments, questions?

12 Okay. Next steps. We would like to  
13 receive your comments by next Friday. Not this  
14 week but the following week, June 15. Once we get  
15 your comments and suggestions we'll regroup, get  
16 together, talk to the Commissioners, talk to the  
17 advisors, and see where we proceed from there. We  
18 are expecting to finalize the report by the end of  
19 July. It can happen before but this is what we  
20 are expecting to do now.

21 Again keep in mind there is going to be  
22 another workshop that will touch on natural gas  
23 that will be August 13. And I don't know whether  
24 this has already been advertised or not but this  
25 is what we have been given. That we are going to

1       be discussing not just natural gas but how to  
2       integrate natural gas into the scenario project  
3       that is underway for the 2007 IEPR.

4               And with that, Commissioner Geesman, if  
5       you have any concluding remarks. That's all we  
6       have.

7               ASSOCIATE MEMBER GEESMAN: I think it  
8       has been a very productive day. I want to thank  
9       you all for participating.

10              MR. TAVARES: Thank you very much and  
11       we'll adjourn.

12              (Whereupon, at 4:25 p.m., the Committee  
13       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 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.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of June, 2007.

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