STATE OF CALIFORNIA - THE RESOURCES AGENCY
BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of,	)	Docket No. 11-IEP-1K
	)	
	)	Joint Integrated Energy
	)	Policy Report (IEPR)
Preparation of the	)	and Electricity and
2011 Integrated	)	Natural Gas (E&NG) Committee
Energy Policy Report	)	Workshop on Natural Gas Market
	)	Assessment Reference Case and
	)	Scenario Results

CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
First Floor, Hearing Room A
Sacramento, California

TUESDAY, SEPTEMBER 27, 2011
10:00 A.M.

Reported by
Kent Odell

APPEARANCES

Commissioners

Robert Weisenmiller, Chair, IEPR Committee
Karen Douglas, Commissioner, IEPR Committee
Carla Peterman, E&NG Committee

Staff Present

Suzanne Korosec, IEPR Lead
Ruben Tavares
Leon BRATHWAITE
Ross Miller
Ivin Rhyne

Also Present (* by WebEx)

Dr. Kenneth Medlock III, Baker Institute at Rice University

Catherine Elder, Aspen Environmental

Mia Vu, PG&E
George Wayne, Department Head, Manager, Strategic
Market and Analysis, El Paso Western Pipeline Group
Lee Bennett
Scott Wilder, SoCalGas
Bill Wood, CEC
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P R O C E E D I N G S

SEPTEMBER 27, 2011 10:04 A.M.

MS. KOROSEC: All right, I think we'll go ahead and get started now that we have all of our Commissioners. Good morning. I am Suzanne Korosec and I manage the Energy Commission's Integrated Energy Policy Report Unit. Welcome to today's workshop on Natural Gas Market Assessment Reference Case and Scenario Results. This workshop is being conducted jointly by the Energy Commission's Integrated Energy Policy Report Committee and Electricity and Natural Gas (E&NG) Committee.

Before I turn things over to the staff, I'll just cover a few housekeeping items and talk a little bit about how this effort fits in within the 2011 IEPR.

For those of you who may not have been here before, restrooms are out the double doors and to your left in the atrium. We have a snack room on the second floor at the top of the stairs under the white awning for coffee and snacks. And if there is an emergency and we need to evacuate the building, please follow the staff outside to the park that is kitty corner to the building and wait there until we're told that it's safe to return.

Today's workshop is being broadcast through our WebEx Conferencing System and parties need to be aware that you are being recorded. We will make an audio recording available a couple of days after the workshop and a written transcript will be posted on our website in about two weeks.

During the public comment period at the end of the workshop today, we'll take comments first from those of you here in the room, followed by those participating via WebEx. When making comments or asking questions, please come up to the center podium and speak into the microphone so that we can make sure that your comments are in the transcript and that the people participating on WebEx can hear you. And it is also helpful if you can give our Court Reporter your business card when you come up to speak, so we can make sure that your name and affiliation are correct.

For WebEx participants, you can use either the chat or raised hand functions to let our WebEx Coordinator know that you'd like to make a question or comment, and we'll open your line at the appropriate time.

We're also accepting written comments on today's topics until the close of business October 11th, and the Notice for today's workshop, which is available on the table out in the foyer and also on our website explains the process for submitting comments to the IEPR docket.

The Energy Commission is required to prepare an

Integrated Energy Policy Report every two years that includes assessments of energy supply, demand, price, delivery and distribution. Based on these assessments, the Energy Commission provides recommendations in the IEPR for policy actions to ensure reliable, affordable, and environmentally benign sources of energy for all Californians. Today's workshop is to get public input on the staff's Natural Gas Market Assessment which includes an update of current natural gas trends related to supply, demand, infrastructure, and pricing, as well as input on staff's Reference Case and scenarios that portray possible future estimates of natural gas demand, supply and prices.

As part of the 2011 IEPR Proceeding, we have held two previous workshops related to this topic, the first on February 24th, which covered Economic, Demographic, and Energy Price Inputs for the Energy Commission's Forecasts for Electricity, Natural Gas, and Transportation Fuels. The second workshop was a staff workshop on April 19th on the Natural Gas Market Assessment Reference Case, Post-Scenarios, and Safety and Reliability Implications of the San Bruno Incident.

The input from today's workshop will be reflected in the Draft 2011 IEPR, a revised schedule of which was posted on our website yesterday. Under the revised schedule, the Draft 2011 is anticipated to be released for public comment on December 1. Unlike past years, we will not be holding a workshop on the Draft IEPR, but instead will be seeking written comments which are due December 22nd. After considering those, the IEPR Committee will revise the report and release the proposed final 2011 IEPR on January 24th for formal adoption at the Commission Business Meeting on February 8th.

Because the Final Natural Gas Market Assessment is scheduled to be released in December of 2011, we plan to include a summary of the final results of the assessment in the proposed final 2011 IEPR that will be released in late January.

So with that, I will turn it over to the dais for opening remarks.

CHAIRMAN WEISENMILLER: Good morning. Welcome to the Energy Commission. Obviously, natural gas is marginal fuel for us on the electricity side, so it sets a key role in our power production and also in our pricing. So we're looking forward to an interesting conversation today; there are obviously a lot of uncertainties and questions that we'd like to understand better.

COMMISSIONER DOUGLAS: Good morning. Welcome to the Commission. I'm looking forward to the workshop.

Thank you.

COMMISSIONER PETERMAN: Good morning. Welcome to the Commission. Glad to be here at this workshop today. I thought this was a very good report that staff has put together and I just wanted to highlight a couple things that are mentioned in the report, but are good things to consider as we move forward and get into the details.

First is about forecasts and what the value of them is to us as a Commission and to our various stakeholders. So I would say we don't expect forecasts to be predictive of the future, but we do expect them to inform us about possible futures, and I think the scenarios that staff is presenting do that. Particularly, what I like about what staff has done with this is that they're looking at a range of plausible underlying conditions and that can be useful. We don't want to be in a position of being surprised and, so, as you see with the different scenarios, there are various assumptions that lead to high and low natural gas prices and I think we can see a range of plausible futures in the scenarios that staff has presented.

I will say, though, that despite the ability of anyone to accurately predict natural gas prices or gas market outcomes, people like myself and the Chair and Commissioner Douglas still need to make decisions based on some expectation of what those outcomes might be, which is why we put these forecasts together.

I encourage, and I believe staff is committed to using these models to develop insights, rather than simply quantitative results, and we can use these insights and our quantitative results to compare to other scenarios that are out there, other results that are out there, and most importantly to evaluate alternative scenarios or a future using different sets of assumptions. I think what staff has done in this regard has been useful and I look forward to hearing your feedback. Thanks a lot.

MR. TAVARES: Okay, Commissioners, good morning. Good morning, Advisors. My name is Ruben Tavares and I am part of the staff here at the Energy Commission.

During the last three IEPR cycles in 2005, 2007, and 2009, the Commissioners expressed concerns regarding the methodology and the model that staff used to generate natural gas perimeter outputs. The Commissioners recommended to staff, and I quote -- that was in the 2005 IEPR -- "to investigate alternative forecasting methods to better assess future gas prices."

In the 2007 IEPR Report, the Commission also directed the staff to conduct a rigorous verification of natural gas supply and price. And, finally, in the 2009

IEPR, the Commissioners further enforced their previous direction, indicating that the uncertainty associated with predicting major input variables and resulting natural gas price forecasts, questioned the value of producing a day-specific specific single point natural gas price forecast. Again, that was in the 2009 IEPR Report.

Given these directions, staff is now proposing a different way to address the Commission’s concerns. As indicated by Commissioner Peterman, we do not expect our forecasts to be predictive of the future, but we do expect to be informative about possible future outcomes.

The new approach entails developing a Reference Case as a starting point in several possible scenarios. Because of the time it took to review the methods and models, staff did not have adequate time to independently develop and populate a model with data, therefore the staff proposed at the February 24 and April 19 workshops to develop a California natural gas Reference Case based on the Rice University Reference Case. In addition, staff also proposed to simulate six cases besides the Reference Case. This step implies changing assumptions and inputs to the Reference Case to generate different outputs.

The scenarios included are high price and low price cases at the national level, a restricted production shale case, California high and California low natural gas demand cases and, finally, a case where the pipeline pressures for the Baja and the Redwood paths will be reduced to observe potential impacts in the market.

In order to generate the California Reference Case and the rest of the cases, staff worked very closely with our consultants, Professor Ken Medlock of Rice University, and Katie Elder of Aspen Environmental.

Today we have four presentations that will detail the inputs, assumptions, and outputs of the cases we’ve developed. Dr. Medlock will present the Reference Case. He was initially planning to be here personally with us, but he got ill late yesterday, and could not travel. Nevertheless, he is joining us through the WebEx and he will be presenting his material remotely. He also will be available for questions any time during the workshop.

Our second presenter is Leon BRATHWAITE, he is part of the Commission staff and he will address the national high and low price cases, in addition to the shale constraint case. Our third presenter is Ross Miller of the staff and he will be presenting the California focused results from all cases, including the high and the low California gas demand cases. And finally, Katie Elder will describe the pressure reduction case.

To help us in the discussion of these cases and other relevant natural gas issues, we invited George Wayne from El Paso Natural Gas. George is the Department Head and Manager of a Strategic Market and Analysis for El Paso Western Pipeline Group, which is a division of El Paso Corporation. He currently oversees the analysis for six of El Paso's interstate gas pipelines, including the Ruby Pipeline. He prepares gas production, demand and price and projections for the western United States, Canada, and Mexico for El Paso.

Our other discussant is Lee Bennett, he is the Manager of Pricing and Business Analysis at TransCanada. He has spent 22 years in the natural gas industry and he has held positions with major natural gas pipelines and marketing companies.

Scott Wilder is a Business and Economics Advisor at SoCal Gas and has worked with the company since 1993. He specializes in economic forecasting and he has also worked in the past on forecasting electricity demand for PG&E.

Mia Vu, she joined PG&E late last year, she is the current Manager of Natural Gas Policy, Planning and Strategy at PG&E. Mia has extensive experience in many facets of the energy industry, including oil, electricity and natural gas.

Finally, Amy Mall is joining us on the Web, she is the Senior Policy Analyst for the Natural Resources Defense Council and she focuses on protecting public lands in the west and promoting responsible energy development. She has served as an Advisor to the Director of the White House National Economic Council and has worked for U.S. Senator Dianne Feinstein and former New York Governor Mario Cuomo.

Today's workshop focuses on Natural Gas, the results of our modeling efforts. Each and every result is presented to you for comment, and we will be accepting comments on today's topic until the close of business October 11th of this year, 2011. The Notice for today's workshop, which is available on the table in the foyer and is also on our website, explains the process for submitting written comments to the IEPR Docket.

Are there any procedural questions before we start? Okay.

MR. RHYNE: Good morning. My name is Ivin Rhyne and I manage the Electricity Analysis Office of which the Natural Gas Unit is a part. Before we jump in, I want to emphasize one thing for those who are participating via WebEx and also who are in the room. We have a relatively distinguished panel joining us today and we've broken this workshop up into some logical pieces, intending to spur some discussion with regard to the elements, the results, and what those results infer. However, we don't want to limit ourselves to the questions that are put forward in the agenda, nor do we want to limit the input to simply those who are a part of the panel. And so I want to, before we get started, encourage those who are here, as we go through the day we're going to stop after each of these sections, we think these breaks are logical in the sense that they kind of capture large pieces together; we're going to stop, we're going to ask some questions, we'll ask our panelists some of these questions, but we also want to encourage both questions and answers from those who are in attendance both in person and on the Web. And I think that, if we have that kind of an input, it will make this a much more productive and interesting day for everyone involved.

So I just wanted to encourage that before we get started and I'll be back at the end of this to wrap the day up. So, with that, I'll turn it back over to Ruben.

MR. TAVARES: Okay, thank you. I think we're going to start with our first presenter and that is Dr. Ken Medlock. Again, he is in Houston, but he's joining us remotely. Ken, are you there?

DR. MEDLOCK: I am.

MR. TAVARES: Ken, we're going to start with your presentation and just a minute here.

DR. MEDLOCK: Okay, I guess I'll just give you direction to change the slides as we go? Is that correct?

STAFF: Yes.

DR. MEDLOCK: Okay. All right, so I think you got a good sort of recap of all that's sort of gone into what I'm about to talk to you about. There is a lot of detail in here that's been added specifically for the work being done by the California Energy Commission that was not part of the Rice University Original Reference Case and, in particular, that detail focuses on Energy Infrastructure in the Western United States. So I will try to highlight a lot of that as we go through this, but also bearing in mind, I'm going to tell you a little bit about the broader model itself so you can understand the context in which everything sits. Next slide. Again. Next slide, sorry.

Basically, what the World Gas Trade Model is, and I'll avoid using the word "Rice" in front of this because I understand what I'm going to present with regard to results is actually the California Energy Commission's Reference Case, it really is a tool that's been developed to examine potential futures, not necessarily predict a specific outcome because there are lots of variables, as we all know, around which there are tremendous amounts of uncertainty from as simple as understanding what economic growth will be over the next five years to understanding what sorts of environmental policies and energy policies might be adopted to influence outcomes in the next decade or so. And whenever you sort of build a model in which you're going to simulate a particular future, you have to take a stand on all these sorts of things, so that's why what you typically try to do is have a tool that's flexible enough to understand sensitivities around that baseline, whatever that happens to be. And what I'm going to present to you today is in terms of the Reference Cases is that baseline, it's by no means meant to represent what I think, you know, if you were to ask any individual member of the staff, or myself, you know, what we actually think the real outcome would be, we might all actually have very different answers, but this is a Reference Case that we sort of agreed on and it's an agreed upon baseline for which we could develop scenarios around.

The model is actually very very detailed. There are over 290 different demand regions represented in the model. Globally, there are about half that in terms of the number of supply regions -- I'll get to those in just a minute -- but, on the demand side, there is a difference in the way demand is treated in the United States vs. other places in the world, and that largely owes to data availability, which is, you know, you get outside the U.S. and you run into these -- let's just put it this way, if you're doing data analysis, it's nice to be doing data analysis on the United States because of the manner in which that data is actually disseminated. We can actually estimate demand functions that are much more sort of granular and sector-specific, so what you see here is a quick snapshot of the types of equations that are actually estimated for the commercial, residential, industrial, and power generation sectors. There is a tremendous amount of sub-state detail represented within the model and that's largely to capture the notion that you have to really site sinks, so demand locations appropriate along pipeline networks if you're going to try to simulate flows in any reasonable fashion. And so there's a tremendous amount of care taken in detail sort of in the model with regard to location of demand, as well as what those projections for each individual sector might be.

As you can see from these equations, you know, there are a lot of inputs. "Y" would be Gross Domestic

Product, so it’s an income variable; Heating Degree Days would be “HDD;” Cooling Degree Days would be “CDD;” Population is “POP.” So there’s a lot of things that you have to assume going forward, these are what we typically call exogenous assumptions. So typically what we do is we assume normal weather, we assume population growth that is in line with United Nations Median Projection Outcome, not only for the U.S., but the rest of the world, and income growth. There is a bit of a recovery in line with some of the work that the International Monetary Fund has done, but long term growth rates are on the order of 2.7 percent. Next slide.

For the power generation sector, taking an econometric approach sort of in its purest form is not really adequate because you’re talking about something that is very much influenced by policy and so you can have significant structural changes across the board so that you can in effect deviate from historical patterns in a dramatic way, in a short period of time. So what we actually have done is estimated a model that has a fair bit of structure in it. And so what you actually have is natural gas competing against other fossil fuels for a space that is in effect defined by whatever sort of policy driven assumptions, you know, staff wants to make about nuclear power, about renewables, about hydro, so on and so forth. So what that means is, in effect, if there is a Renewable Portfolio Standard that we want to actually target, we can actually make sure that the state hits that target in the specified year and given projections about generation in the power sector, we can once we've taken that projection about RPS on board, we can envision and write a forecast for natural gas demand. Next slide.

Outside the United States, as I said, estimating demand is a little bit different, it's done more on a total primary energy basis rather than as distinctly defined by end use sector and, again, that's owing to data availability. Next slide.

A lot of what is done, you have to remember, we're talking about long term forecasts, you really have to have a really sort of strong baseline with regard to the manner in which energy demand is influenced by economic growth and overall long term economic activity, and so there is a lot of literature that this model leans on, which is in effect summarized in this slide. Next slide.

Understanding what long term growth rates are, though, is difficult at best. And, again, we lean on literature here, economic literature about growth and a phenomenon called "conditional convergence," which is the notion that per capita growth rates will converge to a long run growth rate, acknowledging there can be significant scatter and there can be actually differences in the rate of convergence across countries and across sort of windows of development, and that's really what this is meant to represent. I don't really want to dwell on this too much. If there are questions, we can certainly come back to this. But it is important to understand that, you know, certain countries will by definition from where they sit relative to this sort of a picture, have very high growth rates for a long period of time, China being one. Next slide.

And, as a matter of fact, this is a demonstration of that principle. You can see that the long term growth rate for China here through 2030 on average is about 6.5 percent GDP -- that's in real terms, not in nominal -- per year compared to the U.S. which, in per capita terms, is about 2 percent. So it's very strong and this obviously has implications for global market developments, which eventually matriculate into affecting the U.S. market. Next slide.

On the supply side, there is again a tremendous amount of detail, a lot of care taken in trying to distinguish between types of resources, so it's not just identifying a technical type of a resource at a proved reserve, it's actually trying to distinguish the differences between conventional coal, but methane shale and, you know, tide gas as well, and the associated characteristics with the development of all of those. And all that information is actually taken in in terms of the resource sizes and the characterizations to develop cost curves. The basis for a lot of that development -- cost curve development -- is the National Petroleum Council Study that was done in 2003, there was tremendous amount of geologic detail that was uncovered in that particular study and a lot of people have criticized the study itself, but it's one of those "don't throw the baby out with the bathwater" kind of things because there's a tremendous amount of very good work that was done there and we've utilized a lot of it to develop these cost curves for regions even outside of North America where you have very little information about the cost of development itself because a lot of that, quite frankly, is proprietary, but you have very good information about geologic characteristics of plays all over the world, and so we utilize that information to generate costs for those regions. Next slide.

This is sort of a snapshot. It's kind of difficult to read, but in the upper left is the Former Soviet Union, this is a Production Marginal Cost Curve.

Moving across the page, you see the Middle East. Everything sort of on the bottom axis is in trillion cubic feet and, so, really the point about throwing this up here is, if you look below the Former Soviet Union is North America and, yes, there’s a lot of shale in the assessment, but when you compare that to assessments for conventional resources in the Former Soviet Union and the Middle East, you realize very quickly that, yes, there’s a lot of gas here, but there’s a lot of gas there, too. And a lot of it, well, most of it is actually in terms of what has been assessed of the conventional variety, which makes it a little bit lower cost. And that actually has a bearing on the kind of outcomes we see in the model. Next slide.

The model actually does make investments, there is no sort of assumption about what the supply curve in any given period looks like, so you will have very different sort of outcomes with regard to what is ultimately proved and produced depending on the kind of scenario you run. Basically what you have to do is load up a cost of supply curve; so, what does it actually cost to develop this resource? And the model will actually look at the rates of return on different types of investments and make the investment that actually makes the producer better off -- best off. And this is all done in the competitive environment, so there is no non-competitive behavior and certainly that is a, you know, in terms of modeling a Reference Case, that is an assumption because obviously when you think of the gas market, you can think about all sorts of instances where non-competitive behavior sort of dominates outcomes, particularly if you go outside of North America. But we try to capture some of that through changing the required rates of return on investment on different types of regions, particularly areas where we see there might be more of this towards -- gas indexation to oil will actually have contract dominated terms on certain sorts of supplies that are for oil index, so there’s a lot of thought, if you will, that goes into trying to model those kinds of peculiarities in the market. But in a more fundamental way, when you look at sort of projecting things in the long term, you can’t really make assumptions about, well, what will the European gas market look like 30 years from now. Nor can you do the same for the U.S. markets, so we have to sort of let the commercial considerations really drive a lot of the more longer term outcomes, recognizing however, that required rates of return on investment will vary by region and that’s largely reflective of risks associated with gas investments, specifically in those regions. Next slide.

This is a sort of a generic representation of what -- it's a sample, if you will -- of the costs that are actually loaded in the model. This is all in real 2005 dollars and that's an important sort of thing, it's not actually on this slide, but -- and it does not include investments at the wellhead and sort of gathering up to the liquefaction plant, but this gives you an idea of what's actually in the model. And you can see there's a lot of deviation with regard to sort of regional cost, arctic being the most expensive and you move into Australia and that's actually quite expensive northwest shale, in particular, because a lot of the environmental constraints that are placed on developments there. Next slide.

So more on shale. This has sort of been the news of the day, if you will, or of the decade. Next slide. First, and this is for those of you with a geology background, you might recognize this as a modified version of a McKelvey Diagram, it really is just meant to represent what we are trying to capture. The big blue bubble is meant to be resource in place, so that's all gas in place -- it's by no means all going to be ultimately recoverable -- to sort of get an understanding of what is ultimately recoverable, you have to move down to the second largest bubble, which is the Technically

Recoverable Resource and, you know, that can change over time. As a matter of fact, what we've seen in the last 10 years is a dramatic shift in the size of that particular bubble owing to innovations in the field directly related to shale. Then, a smaller subset of that would be what is Economically Recoverable, and the difference in the size between that Economically Recoverable resource and Technically Recoverable Resource is, you know, a source of a lot of debate, quite frankly, among analysts largely because what is economically recoverable is defined by what is the actual cost of lifting a resource. When you think about Technically Recoverable, it is sort of cost independent, it's just we have the technology, we can get to it regardless of cost, but that Economically Recoverable resource is really what matters, particularly when you think about simulating or projecting outcomes. Next slide.

The other thing that is important to understand, and I say this is important because, when you think about projecting things, you have to take a stand on the cost environment and the fact that you're projecting. And to an extent, the model does allow for uplifting cost to the -- and when I say that, I mean, you know, if you actually have an increase in drilling activity, the model does have built into it some cost inflation, but it will not necessarily represent all cost inflation and what I mean by that is it’s easily sort of identified in this kind of a picture. You see Real Oil Price and everything is done on an index basis in this chart, that’s why there are no units, so they are dimensional and this just makes everything comparable. The Real Oil Price from 1980 through 2009 is actually the blue line. The other two lines, the red and the green, are indices of costs associated with oil and gas upstream developments. The Real Well Cost is the red line, that’s actually from EIA; the green line is from the KLEMS database, that’s actually a database that is FIC code specific from the Bureau of Economic Analysis. And the thing that you should note is that all three lines are moving together. And that’s actually a very important point because, when you think about what kind of cost environment you’re projecting, if you put yourself back in the sort of mid to late ‘90s kind of cost environment, you’re going to project a lower price world because, by definition, you’re building cost curves that are lower. If you put yourself in the 2008 sort of cost environment, you’re going to project a higher price world because the marginal cost supply will by definition be higher. So what we’ve typically tried to do is take the mid trend through a much larger cycle because this data actually extends -- this is for exposition only -- the data extends back into the '50s, so what you actually see is sort of a mid-trend, if you will. And part of the point here is to recognize that costs will change over time and there will be cycles in the process, and so that can actually move you around any sort of Reference Case outcome that you would try to model. Next slide.

So if you just take a step back 10 years, the world was sort of painted as one in which natural gas would be flowing to North America in the form of LNG, and yet a sort of rush to build LNG import terminals; there were at one point 47 different terminals that would receive certification or were in the application process, nobody thought they would all get built. But this picture sort of tells you why we had that view. What you have here is compositive satellite photographs on clear nights around the world. You can see where all the little white dots are that those are where the lights are on, those are demand sinks. So that's where we consume energy, not just natural gas, but energy. You can see the eastern half of the United States, Western Europe, Japan, South Korea, if you could put a time lapse -- and there is some interesting work being done by some researchers at Purdue actually that have done this, putting a time lapse on sort of the brightness of these kinds of pictures over time, and you can actually get a better measure of what economic development is meant for energy demand, and you can see actually India and China in certain areas getting brighter over the last couple of decades.

The other thing that is superimposed on this picture are blobs of color and they go from the deep red down to a sort of purplish blue that kind of disappears in the background. Now, the brighter the color, the more intensely endowed the region is with conventional gas resource. And this is the snapshot of the world that most people had when they were thinking about, well, what will the world look like? What will North America be like when you think about natural gas going forward? And so, you know, a lot of development is tied to West Africa, tied to the Middle East, to move gas into the eastern gulf coast. Next slide.

There had been a lot of work and understanding what the global shale gas resource was prior to all this, though. As a matter of fact, it doesn’t take much effort to find dissertations that were published in the early to mid-1970s, talking about resources in place, or gas in place, gas content of a shale formation. So, to a lot of geologists, shale was a known quantity, it really was just an issue of a technology waiting to happen. And so, to a lot of people who sort of followed this a long time, this really is a technological revolution, it's not as if we've just miraculously found something we didn't know was there. And so that's really what has made this, I think, happen so quickly is once the technological hurdles were crossed, you were able to make a lot of resource that you knew was in place extractable in a very short period of time. Next slide.

Some recent updates of the data that Rogner put together back in the late '90s, which is part of a UN Program, actually indicate that the resource could be even larger. As a matter of fact, there was some data work done by Advanced Resources International funded by the Energy Information Administration, I'm sure a lot of you guys have seen the report. Not all of this resource is in the Reference Case Model, and a lot of that is because what we could incorporate largely owes to, you know, there is a time lag in terms of understanding what's in the Technically Recoverable Assessment and then actually building a cost curve associated with that based on the geologic properties of the shales, and so there's nowhere near what you see down there at 6,600 TcF in the model. But there are some shale resources that are located in other parts of the world besides the United States, which do influence the outcome a little bit.

Next slide.

And so, as a matter of fact, what shale has done, or technology, I really should say, has done is change the way we sort of view the natural gas world. As a matter of fact, you take that satellite photograph and you superimpose on it where all those shales are, and you see that the location of a lot of this resource is quite strategic, in fact, because you know there's a high coincidence in terms of its location and where the lights are on, and so that actually makes it attractive not only commercially, but from a lot of geopolitical angles, as well. Next slide.

Obviously, there has been an evolving state of knowledge in the 2003 study that are referenced before the technically recoverable assessment that the NPC actually adopted, it was only 38 trillion cubic feet for all of North America, so that's obviously a low number. By 2005, some activity had really started to commence or take shape in the Barnett and the Fayetteville, in particular, those two shales and, so, most estimates place that resource in terms of what was Technically Recoverable at around 140 tcfs; as a matter of fact, that's what EIA was using in its work at that point.

Then there were several other studies that sort of followed on the heels of that and you can sort of read the numbers yourself, but the point is you can see the number gets bigger every year. And so that's really -- that trend really owes itself to a better understanding and delineation of the resource itself. The work that we've actually done at the Baker Institute indicates a technically recoverable resource of about 630 TcF. Next slide.

And this sort of lays out exactly how that resource is distributed according to the Reference Case and the breakeven price associated with each one of those resources. Now, the breakeven price is really there meant just to be sort of a reference point, if you will. It is a point on a cost curve and it's meant to represent roughly where you can get to about -- it's not the first entry point, it's about 50 percent of the resource and the slope of the curve, so in some ways the breakeven prices listed here might be a little misleading, will vary by shale. So you have some relatively low cost resources that are ultimately what is targeted first, but then, as you moved through time, you have to target higher and higher cost resources. So that's where you see in some of the larger shale plays the tiering that's done, so on and so forth. Next slide.

There is a lot of uncertainty not only inside North America, but outside North America, probably increases by an order of magnitude with regard to what the actual cost of development will ultimately be. One of the biggest issues with shale developments sort of outside of North America is actually market structure. It’s a fact that it’s often under-appreciated, but a lot of what we’ve seen in the United States owes itself directly to market structure, so you know, the fact that you have unbundled capacity rights, transportation -- transportation services are unbundled from ownership of the facility -- that actually helps because it basically means anybody can bid for the right to move gas. If you think about most places, with the exception of Australia outside of North America, that’s not the case, you typically have a large compass that can block access by any sort of small developer, so that’s a pretty important facet to sort of take on board when you think about what’s actually happening in the United States.

Another thing is the manner in which property rights are actually allocated and accessed. You know, in the United States a lot of development owes to developers being able to directly negotiate with landowners, whereas if you go outside of North America, that’s generally not the case either. Next slide.

And so what you actually see in the model, just so you understand what’s in there, there is about 800 TcF outside of the United States. A good chunk of it is in Canada and Mexico. A lot of the Mexican shale is relatively high cost and that is largely because what you're talking about, particularly when you think about the Burgos and Sabinas Basins, are shales that are extensions effectively of the Eagleford shale which is in South Texas. The trouble, though, there -- a lot of people have probably heard about the massive amount of growth that is occurring there and a lot of that owes to the NGLs that are associated, the liquids that are associated with development. As you move farther and farther south, you get into drier parts of the fairway, so you're talking about a higher cost in effect on a per unit basis of production because you don't get that liquids uplift, and so that's actually another important point there. We actually have a well economics model that is used to develop these cost curves and there are liquids credits applied when there is a liquid content associated with the gas stream. Next slide.

And again, this is sort of a rehash of some of the other things, but there are multiple issues that face shale development, so when we think about generating a Reference Case projection, it's important to understand that there are some things that are global and some which are actually regional and specific to the United States, in particular, that could alter the course. And so understanding the simple fact that a lot of that is policy related is important, particularly if you want to understand what any given sort of simulation might actually mean, and understanding its likelihood of occurring. Next slide.

And so now we can sort of dive into some results. Before I do this, are there any questions? Does anybody have any questions just about the model itself?

COMMISSIONER PETERMAN: Hi, Dr. Medlock. This is Commissioner Peterman. How are you?

DR. MEDLOCK: Hi. How are you doing?

COMMISSIONER PETERMAN: Good, thanks. I did have one question about your assumptions around RPSs for the different states. What is the rationale for assuming that states meet their RPSs five years later in the base case?

DR. MEDLOCK: Okay. The base case -- there were a couple of reasons. We went through a pretty massive recession and, by some accounts, we still are in the middle of it, but what that did is it actually put some stress on state budgets, it put some stress on -- and, you know, by association it put some stress on the ability to actually meet some of these projections because what you end up doing is particularly in places where some of the RPS push is supported through State budgets, or State Government budgets. It was more, you know, we look out, we see what did the recession do, maybe it delayed economic development by five years. And so you sort of shift the budgetary constraint by five years and that's effectively what happened. In our own work here at the Baker Institute, we would actually have that five years applied to California, as well, but given the impetus at the CEC, we actually went ahead and had California meet its stated goal in the Reference Case. And, you know, we actually in looking at this, a lot of this work is done in the spreadsheet that is sort of modeled so you can develop a reference input for the model. You can see that, in certain states, you know, trying to force that to occur, particularly states where you have relatively low gas consumption to begin with, you're basically squeezing gas almost completely out of the picture, and so, by a lot of accounts, that's just not a very realistic outcome. So there is some modeler judgment sort of overlaid there.

COMMISSIONER PETERMAN: Great, thanks. That helps.

DR. MEDLOCK: Sure. So when you look at the Reference Case, this is really just meant to demonstrate what the composition of U.S. production is from 2010 through 2040, you see that shale gas production does grow in the Reference Case to be in excess of 50 percent by roughly the early to mid-2030's -- actually, in this case it is by 2030 at 50 percent, but the point is that resource assessments that we just went through is really what is driving this particular outcome.

The Canadian shale is not pictured here, but there is fairly strong growth from the Western Canadian shales, in particular. It reaches about a third of total output in the 2030's. Now, one of the things that is also happening in Canada is you've got strong declines in the conventional resources, and so largely what that is doing is just offsetting the decline, allowing for some very modest growth, some of which is soaked up in oil sands developments. Next slide.

And so, to actually understand clearly what's happening with shale by basin or by play in all of North America, that's what this slide gives you. Everything below that dark red is the United States. If you go from the red to the orange, sort of deep red, that's Canadian shale, and then sort of farther north of that is where Mexico begins to sort of enter the fray in the late 2020's. What you can see from this slide is there are some very high growth regions, mainly the Marcellus, which is that big wedge at the bottom and actually I was just looking at some data the other day and it turns out this prediction for the Marcellus is actually an under-prediction of where it actually is now, so that -- kind of throw some water on that particular graphic, but there's actually a very important point that I wanted to make on this, it's that developers, as they move into these shales, are learning a tremendous amount about the resource itself and about the geology itself, and a really good case in point, if you look at the Barnett shale and you can actually access well filed data through the HPDI database for the Barnett, you can actually see bottom hole locations vs. where the pad site is and understand how developers have been moving through that shale, and there have been over 14,000 wells drilled in the Barnett, so that it's a very rich data source to sort of understand how developers will move through shales and learn as they go. What you can actually see is from an existing pad site very early in the development of the Barnett, it almost looks like a spider web, so developers were sort of shooting laterals in multiple directions trying to figure out the optimal sort of way to drill up that particular play, and then you will see sort of, if you put a time lapse on that, you move away from the spider web maybe 40 to 80 acres and you start to see the same developer laying what almost look like railroad tracks if you're looking at a topology of the resource. So what that is telling you is that they're figuring out the best way to attack the shale and it's very evident in the Barnett because what you've actually seen in the last three years is a pretty dramatic decline of rig counts, but the production is held stable. And what that is telling you is they are actually able to target the most high valued portions of the play in a very sort of cost-effective way. And arguably, some of that is actually going on in the Marcellus and the Haynesville, as well, and will probably likely continue. Next slide.

In terms of U.S. LNG Imports, the Reference Case basically sees almost no growth until you get well out into the time horizon. And again, this largely owes to what is going on with domestic gas production. Next slide.

In terms of U.S. demand, this actually gives you a little bit of history too, but the projection you actually see pretty strong demand growth. We do actually hit the 30 TcF point in the mid to late 2030's, which was sort of the point that everybody had their eye on back in the early '90s, albeit, I guess, based on a lot of the projections that were done then were probably about two decades off, but that's okay. A lot of this growth is really driven by the power generation sector, and so what you actually see, given even with all the RPS requirements, is very strong growth in power generation, particularly as it squeezes on the coal generation fleet. Next slide.

For California, you see not much demand growth over the next decade and a lot of that is quite frankly driven by the fact that, in the power gen sector, there's a bit of a squeeze on gas largely because of the RPS Standards. As you move farther and farther beyond that, though, there's a bit of relaxation in terms of the model's functions with regard to the rate at which renewables will grow, and so you do see some gas penetration longer term in the power sector, but it's nothing near as dramatic as what you see elsewhere in the United States. Next slide.

In terms of what's happening to price, a lot of what you see in the trends with regard to price and basis are directly related to what's happening on the domestic gas production scene. Looking at basis, you actually see longer term weakening at AECO and that again is directly related to the fact that there are shale resources coming on line there and it's stressing a little bit on the infrastructure. Then, when you move sort of to the top of this basis graphic, you're sort of thinking about points that are farther east, and you actually do see some long term weakening there, largely because of developments in the Marcellus and what it does to those market areas. And the strengthening you actually see at the SoCal border is not necessarily related to demand growth in California, it's actually related to what's happening to prices farther east. All the production growth that is occurring in the Gulf Coast Region and in the Mid-Atlantic shales, for example, is really keeping prices from elevating as much as they would otherwise, and that actually, you know, by direct relation, is having a modest impact on what's happening at the SoCal border. The other thing, of course, that is happening is you do have some demand growth and so it's not really strong enough to signal massive increases in transportation capacity, and so you do utilize capacity that exists a little bit more heavily.

You also see, and it's not in this slide, some strengthening of the basis in the Rocky Mountain region, which is also directly related to the production trends in North America, in general. Next slide.

Okay, so outside of North America -- before we fully dive into this, are there any questions just in general about what I've shown so far? Obviously there is going to be a lot of detail presented with regard to

North America during the rest of this workshop, but if there's anything I've got to address right now? Okay, I guess we'll go ahead and keep moving.

Understanding what is actually happening to the global gas market is important because it helps you to understand a little bit what's going on with prices in North America, as well. The U.S., and again, this is very different than the picture most people had 10 years ago, is among the sort of end-using sort of markets, the lowest priced market, so when you compare the U.S. price to European price and to the Asian price, you actually see that the prices in the U.S. are $1.00 to $1.50 lower long term. And there is a bit of an uptake in price -- I did notice some of the questions that were submitted prior to the workshop –- in the near term, and a lot of that is related to stuff that is happening outside of the U.S., as well as some stuff that's happening inside the U.S., so there are a couple things going on here, 1) you do see some stronger demand pull from what actually happened at Fukushima, you also see some stronger demand pull due to an economic recovery that is assumed to occur globally over that window in time. And the reason you see that sort of down dip, if you will, in the 2014-2015 time frame is directly related to some fairly large contract and supplies coming on line in the Northwest shelf, in particular in Australia, which tend to sort of reverse the increase, if you will, that you see in that first couple of years. So what that tells you is that there are some things that are sort of hard wired, if you will, that could cause some decent up and down, if you will, in terms of average annual prices over the next couple of years. Next slide.

With regard to composition of production in Europe, you see some shale coming on in Europe, it doesn't really happen nearly as fast as what we've seen in the United States. Just for those of you who are following this, there is no shale production in France. The ban on hydraulic fracturing is honored in the Reference Case, and so none of that is actually available as an identified resource in France. Next slide.

Russia really sees its market share affected pretty dramatically by a lot of what's going on, so we actually just completed a study at the Baker Institute for the Department of Energy looking at what shale is meaning on a geopolitical scale, or what it could mean on a geopolitical scale, and one of the things you actually see is that, if shale developments were to continue sort of as modeled in a Reference Case, Russian market share, although the volumes don't fall that dramatically, market share in Europe actually does fall. It's obviously going to grow in Northeast Asia, but that's because they really don't have much of a footprint there now, but if you were to compare this to a case in which you don't have shale developments, you see a quite dramatic difference. Next slide.

In terms of what's happening in China, there is also some shale gas production and growth there. You can see that in this particular slide in the upper right, it's the orange bit. China really is the driver of the boat in terms of LNG market development because of the tremendous demand growth that occurs there. But you can see that that demand growth is not only by pipeline in LNG, but also by domestic production increases. China actually faces a little bit different, I think, picture than a lot of places when you think about not only a lack of infrastructure to move the gas, but lack of suitable sources of water. There's a lot of areas, and you can see this in that bottom left graphic, where there are shale resources identified, so those are the light green, but those resources, with the exception of the Ordos and Songliao Basins, are highly coincident with areas of high water stress, and so it's going to be interesting to sort of watch what happens in China, what sort of new technologies might come along to sort of help the Chinese endeavor to increase shale production. One of those is actually sourcing deep source -- deep aquifers, which is a sort of briny source of water that is typically not tapped for human consumption, and to the extent that that actually occurs, there are a couple of companies that are actually testing that right now. Drilling those wells actually allows for not only a source of water that wouldn't compete with human consumption, but it allows you to access an aquifer source that you can re-inject into, and you're talking about very very deep briny water that is typically, again, not accessed for human consumption. So, obviously all of this raises the cost of development, so exactly how far that goes and whether or not it proves to be successful is still sort of on the table. Next slide.

Where is LNG going? Well, the U.S. is the tiny thin bit at the very top, it doesn't really look like much, so in terms of U.S. sort of footprint in the global gas market, it's not very large. Most of the action is occurring in Asia, so basically from the bottom of the graph up to that sort of deep sort of reddish brown, which is South Korea, that's all Asia. So Asian customers are really what drive -- growth in Asian demand is really what drives a lot of the developments in the global gas picture. Next slide.

Where is it coming from? Well, in the Reference

Case, Iran is actually allowed to develop later in the time horizon, Venezuela is allowed to develop later in the time horizon, and so you see a pretty diverse source of supply through the mid-2020's to 2030, about half of LNG exports -- well, not quite half, about 35-40 percent of LNG exports -- are coming largely from two countries, and that's Qatar and Australia. But you do see some emergence from some of those other marginal sources like Iran and Venezuela when demand growth continues sort of through the 2030's. And obviously that result can be challenged base on current geopolitical trends, but again you're talking about 20 years into the future, so some of those constraints are relaxed in the Reference Case. Next slide.

I guess that's it, actually. There are some Appendix slides which are in here really just to support conversation around the kind of assumptions regarding international pricing schemes, so on and so forth, which I'm happy to entertain. There is also some discussion about the feasibility of U.S. LNG exports.

What I've done in this particular slide is just take those marginal costs of supply curves that I showed you earlier and put them on the same picture. And one of the things that is important to understand and is tied directly to some research that is apparently involved is the role of the U.S. Dollar and understanding what that actually means for relative costs around the world. One of the things that is certainly true right now in an environment where the U.S. Dollar is about as weak as it's been in the last 40 years is that tends to make the U.S. look like a low-cost region, and this is actually fueling a lot of what you see with regard to the feasibility of LNG exports in the United States. In particular, you think about natural gas markets outside of North America. Let's say I'm in the U.K., for example, gas there is not traded in dollars per mMVt or dollars per Mcf, and it's actually traded in pence per therm. So when you want to convert that back to a U.S. Dollar denominated sort of metric, you have to apply an exchange rate, and so the exchange rate by definition has a pretty strong role in understanding what happens to spreads, not only between oil and gas, oil which is a fully fungible internationally traded commodity, U.S. gas is not, but also between regional gas prices. And so, in the Reference Case, you don't really see much in the way of LNG exports from North America, but that's because the Reference Case is pinning itself to a sort of 2005 kind of world. And what that means in effect is that the U.S. Dollar is in a much stronger position relative to where it is today.

If you run cases, and we've done this, we have not done it for the CEC work, where you impose more constraints and you change the value of the dollar relative to international denominations, you do see some modest growth in exports, but that's largely from Canada, not necessarily the Gulf Coast in the United States. So what this graphic, this particular table actually shows you is that, given the current value of the U.S. Dollar relative to major currencies, and the average is where it's been over the last 30 years, the high is the high over the last 30 years, the low is the low previous to where we are today, and I should actually clarify that – high and low are not actually the highest point and the lowest point, they're actually a peak to the P90 in the distribution of value to the U.S. Dollar against all major currencies. But you can see if you just take an oil price, say $96.15, which is where it was about two months ago, actually, the actual Henry Hub price, given those particular environments, associated with this work that I've been involved in, is depicted in the red and, so, what you actually see is that an average, if we're in a $96.00 world, the price of gas in terms of the low, the price of gas would be close to $8.00, which is closer to that sort of 12:1 kind of ratio that a lot of people used to talk about. The thing that sort of gets lost in the conversation that is the point of this slide is the value of the U.S. Dollar in that conversation. There's a fair amount of stability in terms of where the dollar is set vs. other major currencies prior to the last five years for the preceding 20. The last time we saw a gas oil window that is as big as it is today was in the late '70s and, coincidentally, that's the last time we saw the U.S. Dollar as weak as it is today. So it's a very important thing to sort of take on board when you're thinking about these sorts of issues. And it's obviously another sort of thing to take on board when you're thinking about the relevance of this particular Reference Case vs. what could potentially occur over the next 20-30 years.

I think this is probably a good place to stop and sort of address questions if there are any about the Reference Case.

MR. WAYNE: Doctor, I was wondering what your assumptions are --

COMMISSIONER PETERMAN: Wait, could you state your name? Sorry.

DR. MEDLOCK: There were scenarios designed specifically to address energy, not only in the United States, but California and sort of how policies might sort of unfold to effect outcomes not only in the United States, but also in California, and that's going to be, I think, the emphasis of the remaining presentations. Designing those scenarios was interesting and there was a lot of work that actually went into it. I'm looking forward to actually seeing those presentations as the day progresses, and I'll be hanging on the line to answer any questions that might come up, that if I can address I certainly will.

MR. WAYNE: Hi. This is George Wayne with the Western Pipeline Group of El Paso. I have a few questions regarding your Reference Case, one specifically because it's been out there for a long time, it seems to be about 10 years away in everybody's forecast, it has to do with Arctic gas and McKinsey Delta gas, you didn't really discuss that, and how that impacts your assumptions where you have it coming in, if not. And also, across our borders, the trade in balance that we see occurring between less imports from Canada, more exports to Mexico, that growing trade in balance, and how do you weave that into your Reference Case?

DR. MEDLOCK: Hello?

MR. TAVARES: Yeah, Ken, did you hear the questions? Ken?

COMMISSIONER PETERMAN: Well, could you repeat your question again just for – because I've almost forgotten what the --

MR. WAYNE: Is Dr. Medlock there?

MR. TAVARES: Ken, are you there? Can you hear us?

DR. MEDLOCK: [No response]

MR. WAYNE: Well, I'll repeat my question for everybody else. It has to do with, again, Arctic gas and McKinsey Delta gas coming down from Alaska, you know, that was always a big assumption in most people's forecast, when that was potentially going to hit the United States. I was just wondering where do we weave that into the Reference Case, that particular impact. And then, something that is growing is the trade in balance across our borders, that we see less imports from Canada because we see Canadian decline in imports, that is, and we see more exports to Mexico, again, creating a trade in balance where, well, shale gas production probably absorbed that, but my question is where does that weave into the Reference Case?

MS. KOROSEC: We're having difficulty with Ken's mic is off, so we're trying to email him quickly to see if he accidentally hung up the phone, so….

COMMISSIONER PETERMAN: Does staff have any insight into the questions raised by Mr. Wayne?

MR. TAVARES: I think we want to hold on for a little bit, they are trying to solve those technical issues. But there are some other questions online by now.

MS. MALL: Can you hear me?

DR. MEDLOCK: I can now, there we go.

MR. TAVARES: Oh, okay.

MS. MALL: Yeah, I could hear you before, but I was muted, and then I just got something that said "you have been unmuted" by the host.

DR. MEDLOCK: Oh, okay. I actually just got your chat and it said -- okay, wait a minute, I'm actually sending the thing to Donna.

MS. MALL: Okay, good. I was trying to get anybody's attention.

DR. MEDLOCK: Yeah, I think you and I are the only two that can talk to each other right now.

MS. KOROSEC: Well, we can all hear you, though.

DR. MEDLOCK: I just sent her a note. She asked if my personal phone was muted. It looks like George Wayne was asking a question.

MR. TAVARES: Yes. Ken, can you hear me?

MS. MALL: Well, I haven't heard anything except you.

DR. MEDLOCK: Okay.

MS. MALL: I guess it's worth waiting a little while.

DR. MEDLOCK: They can hear our conversation. We cannot hear you guys, so I don't know what's going on.

COMMISSIONER PETERMAN: Your question has brought down our system, George, thank you.

MS. KOROSEC: We're getting our IT folks here, so I'm not sure what to suggest in terms of continuing the conversation. Maybe we can try to focus on questions from inside the room of staff until we can get Mr. Medlock to hear us.

DR. MEDLOCK: I'm actually chatting with Donna right now, so….

MS. MALL: Okay, I'll just go on hold and wait to see what you can find out.

DR. MEDLOCK: Okay.

MR. WAYNE: Actually, it wasn't as bad as my -- I was in Wyoming Gas a few weeks ago presenting and a dog came into the conference and knocked the mic and --

DR. MEDLOCK: It looks as if –- I'm assuming you guys can hear me -- it looks as if the podium and the list of participants for me is muted, so that would mean you guys could not communicate with me. So you might try to unmute that.

MS. KOROSEC: All right, we found it.

DR. MEDLOCK: There it is. There we go.

COMMISSIONER PETERMAN: Welcome back.

MR. TAVARES: Okay, Ken. I think George had a couple questions for you.

DR. MEDLOCK: Yeah, no problem.

MR. TAVARES: Okay, go ahead, George and start the questions again.

MR. WAYNE: Yes. This is George Wayne with Western Pipeline Group of El Paso. My questions stem from a couple things, one has to do with that we see Canadian exports declining, we see obviously the kind of conventional, but probably more importantly, it has to do with your assumptions of Arctic gas and McKinsey Delta gas, where you weave that into your forecast. And then the last question is sort of in a similar vein, we see, at least at El Paso, growing trade in balance across our borders, less imports from Canada and more exports to Mexico, and again shale gas and other development obviously absorbing that, but just where do you weave that into your Reference Case?

DR. MEDLOCK: Okay. Good questions. Well, in the Reference Case, those developments are not assumed to occur at any particular point in time; rather, the model is actually looking at those opportunities in assessing whether or not they will occur. With regard to the McKinsey Delta opportunity, that actually does not occur. The first time it is allowed to happen in the model, so when the investment logic is basically evaluating that particular opportunity, is in roughly 2014 and given what is actually happening in the Lower 48 in the Canadian gas market, more specifically, McKinsey Delta gas is not ever actually shipped south. The more general question in regard to Arctic gas development, so Alaskan gas is eventually developed if done so as an LNG export, though, beginning in about 2038. So basically what is happening is gas production and gas demand in the Lower 48 are more or less in balance and there's very little room to develop that resource and ship it south, so effectively that's what is going on.

With regard to your comment about the Canadian gas exports to the United States and U.S. exports to Mexico, you're actually spot on with regard to what's happening in the model. You do see an increased flow south, figure from Texas and to the Mexican market, and you do see a decrease in Canadian exports to the U.S.

MR. WAYNE: Thank you.

DR. MEDLOCK: Sure.

MS. VU: I have a question. This is Mia Vu from PG&E. What is your assumption in the model about the long term relationship between oil and gas? That's the first question. And the second is about industrial demand. My observation is that with the availability of gas and low gas price in the United States, it seems to stimulate the petrochemical sector in terms of using gas as a feedstock. We saw some announcement about opening up the old ethylene plants in the Gulf Coast, as well as some new plants are proposed in the Northeast. And it is a first time, not first time, but for a long time, that the U.S. has more of a competitive advantage in the gas side in the past; the fertilizer and all the industries are moving offshore. And also, when you have the gas available in the major consuming region like the Middle Atlantic, you save a lot of transportation costs on the gas side, as well as on the product side, so do you incorporate that in the industrial demand?

DR. MEDLOCK: Absolutely. You do see some modest growth in industrial demand, which is certainly different than if we were to talk about industrial demand trends five years ago, we would have sort of envisioned things, but, yes, there is actually some recovery. We don’t necessarily get back to the same levels we saw in the mid-‘90s, which is I guess where industrial demand was at its peak before it began, again, that’s sort of seemingly at that point a natural decline. But a lot of that owes directly to the fact that you do see softer gas prices in North America, so there is some demand growth in the industrial sector. And with regard to the questions, you know, centering on transportation costs, yes, you do see some growth industrial demand in the Mid-Atlantic region largely because there is a softening of basis there relative to Henry Hub, and that's actually something I showed in the slide earlier. So, absolutely, I mean, the trends in production and the Reference Case directly impact demand response, that's what gives you sort of that demand growth longer term when you look in the industrial sector in the Reference Case.

MS. VU: How about the oil and gas --

DR. MEDLOCK: Oh, the oil and gas ratio, yes, sorry about that. Well, there is an oil price assumption in the model, and one of you guys from CEC is going to have to help me, what did we assume with regard to oil price projection? I want to say we assumed we were in the mid-'90s in the Reference Case here, which means that you see some price recovery with regard to Henry Hub, sort of up into the mid-6's, so certainly not where -- we're not in the 12:1 ratio, but we're certainly inside of the 15:1 ratio long term.

MS. VU: Thank you.

DR. MEDLOCK: Sure.

MR. TAVARES: Any questions? Commissioners, any questions? Okay, Amy, do you have a question for Ken?

MS. MALL: No, I had just flagged before to try to get his attention when we were having the audio problem, I'm sorry.

MR. TAVARES: Oh, okay. Ivin?

MR. RHYNE: Yeah, so we mentioned that we have these kind of discussion driver questions, these key questions here, and I'm going to go backwards a little bit in the presentation to -- there we go -- so this is the reference price case, you see slide 34, you see the prices in 2010 dollars, U.S., Europe, and Asia, you have the peak, and then it kind of levels off there. Ken has talked about the drivers that go into that case. What we're interested now in, both from our panelists and from those who are on the line, as they look at this and they understand the drivers that are involved, what insights or, if I was going to speak more colloquially, kind of what is the story that our panelists kind of see in this draft? And what does that tell us in terms of understanding that this is kind of a business as usual kind of scenario? So I'm curious what our panelists see here.

MR. WILDER: Well, Scott Wilder from SoCalGas and an observation also. A question for you, Dr. Medlock. I believe it's in 2015 that the Panama Canal expansion is due to be completed and that's going to permit LNG cargo ships to go through the canal where, at this point right now, it’s really prohibitive for them to go around the Cape Horn at the bottom of South America, and there seems to be a real opportunity for U.S. Gulf of Mexico gas in that case to be shipped a lot more economically eastward to China and other East Asian countries, and I wanted to ask if you had any assumptions about that in the model and the results.

DR. MEDLOCK: Yes. The Panama Canal option is in the Reference Case. It again, though, is, you know, as I mentioned before, we don’t see in the Reference Case any exports from the Gulf Coast, and that’s why I actually raise the issue about the value of the U.S. Dollar and the fact that a lot of the stuff in the Reference Case stays on sort of 2005 kind of metrics, so that’s certainly something that could be changed if the U.S. Dollar remained very weak, but quite frankly what happens is you don’t see that option being utilized on an average annual basis to any extent, and a lot of that owes to a point that I made about new supplies from Australia. There are a couple of big projects that will begin shipments in the ’14, ’15, ’16 time frame, and if you’re going to compete with those contracted supplies from the Gulf Coast, you would have to have a pretty ironclad contract with the Chinese or Japanese or Korean customer out of a Gulf Coast terminal or you’re just simply going to have to wait for some idle capacity. And given the pace at which supplies are scheduled to come on, that doesn’t look like a bet that is going to bear much in terms of fruition, in terms of delivery across the Pacific from the Atlantic via the Panama Canal option, so it would have to be a contracted flow and, quite frankly, right now there are no contracted flows, so there aren’t any assumed in the Reference Case.

MS. VU: This is Mia Vu again. On the question on the price of the Reference Case, what I observed is, after that blip going up and down, for the long term, what we see here in the forecast is between five and six dollars.

DR. MEDLOCK: Yes.

MS. VU: And even when we go to the national cases, the variation is about that five to six dollars, so my observation is, when I look at the EIA long term forecast, and other forecasts in the industry, the range are larger. We saw the range between four and eight dollars, so it’s a wider range. So that is my observation.

DR. MEDLOCK: I can’t really speak much to that, I’d have to actually look at the specific drivers and the range of cases that you’re actually evaluating. The cases that were constructed, and I’m sure this will come up again and again through the course of the day as those cases are presented, were constructed to try to stimulate some variation in the pricing outcome. One of the things you have to remember, though, is that when you're looking at cases that don't do a lot to deviate the cost of shale gas development, or the availability of shale gas development, is you're not going to see a tremendous variation in the pricing outcome simply because what you're talking about is a very sort of long flat supply curve, in effect. And so that's really sort of what mutes the impacts if you try to derive the deviation and the outcome on the demand side. So what you really have to do to get a significant shift in price is do something to the supply side.

MS. VU: Yes. I observed your cost curve is relatively flat between zero to 600 TcF of cumulative production, so that's one of the drivers, how it happened.

DR. MEDLOCK: Absolutely.

COMMISSIONER PETERMAN: Can I just interject here for a second? This is Commissioner Peterman. Ms. Vu, thank you for asking that question because it's a question I have for staff generally with looking at the low and high price cases, that you do see the range within five to six. And Dr. Medlock, thank you for that explanation, you had Katie Elder here nodding in agreement. But I would just ask staff when we do the final report on this just to highlight that there is this difference with the EIA, and if that is one of the driving reasons, just to point that out because I think it would be useful for all of us. Thanks.

Whoever wants to go next with a question – do you have another question, Ms. Vu?

MR. RHYNE: And were there any other comments regarding the Reference Case, just general insights from either anyone here in the room or online?

MR. WAYNE: I had one question, one granular question that would have to do with California production. I was looking at the Reference Case production and it looked like on the back end of the forecast in 2030 or so, I saw California production increasing and I was wondering what was driving that.

DR. MEDLOCK: Price environment, that's largely what it is. So there are resources in California that, you know, on their own merit, in terms of competing with resources out of the Rockies and other resources that will be imported, Canadian supplies, in particular, you know, are sort of lower in the pecking order in terms of their commercial liability, but once the price environment begins to sort of exceed that sort of $6.00

mark, those resources become competitive, and so that's basically what's happening there.

MR. WAYNE: Well, then -- again, this is George Wayne -- so where are you developing this California resource? I mean, what plays? Is it offshore, onshore?

DR. MEDLOCK: No, primarily it's onshore, it's in the sort of Southern California San Joaquin sort of basin area, so….

MR. WAYNE: Does that have to do with the heavy oil production?

DR. MEDLOCK: It has to do with -- a lot of it is associated production, but it is higher cost is the bottom line and so that's why you don't actually see it occurring. I guess it's a resurgence of fuel, although it's modest, you know, against the backdrop of what's happening in all of North America, but you do see a bit of a recovery in California gas production, yeah, that's right.

MS. VU: I would like to discuss one point about production cost curves. What I notice is that, in the gas industry and even the oil, it's very hard to fine what is the production cost curve unlike our cost information, unlike the electricity industry, you know the production capacity, the generating capacity, you know the marginal cost for production. For natural gas, it's not that straightforward. The data on production costs is really sporadic and people who are doing the modeling need to have a lot of research and assumptions to make that happen. Recently, one large independent producer in the U.S., they claim that their production cost is about $4.60, but those are like a couple points, not a lot of data around that.

DR. MEDLOCK: Right. So I guess what you're asking is how do we develop our cost curves.

MS. VU: Yes, that would be helpful.

DR. MEDLOCK: No problem. That work is largely done through reference to the Well Economic Model that we've developed at the Baker Institute and it's specific to different plays and different resources. And one of the things we actually have access to, and I would highly recommend the CEC, if they wanted to sort of pursue this course independently, you know, pursue a sort of similar vein in terms of the research that we do, we have actually access to a database that is provided by a company called Drilling Info which that database, they recently bought HPDI, it is used in a lot of different sort of industry studies. The reason it is used is because it actually allows you access to well filed data, so it is very specific data with regard to individual wells that are drilled all over North America. And you can actually use that well filed data to develop costs and break even prices, if you will, for different wells and you can then begin to understand whether or not wells are sort of in the money or out of the money, if you will, a very specific sort of data point basis. And what that allows you to do is create aggregates of different well types and that can go a long way and, in fact, it does go a long way in defining sort of what the cost of development for a particular well type in a particular region, a particular play is, in North America. And it is sort of the quick one-minute explanation, but in a well file, you get a lot of information about where the well is located, how much the well has actually produced, not only in its initial phase, but over the life of the well and, you know, the well life will be determined by all sorts of characteristics that are associated with the well and its location, not only by the play it's located in, but also what it is competing against in that play zone and so forth.

One of the things that you actually see, and this is a tremendous sort of uncertainty going forward when you're looking at that data over the last just five years, you actually see that initial production rates for different well types are consistently increasing. You see that projected estimated recovery for specific well types are also increasing, and what that typically tends to do in a particular cost environment is drive down the per unit cost. So, to the extent that that can continue, that's definitely sort of a technology assumption that you have to make going forward and, if it does continue at the pace we've seen in the last five years, then that really does challenge even the Reference Case prices you're seeing here, you know, being in that $5.00 to $6.00 window. In particular, they'll probably be lower.

MR. WAYNE: This is George Wayne again with El Paso. Sort of a general comment. To me, it would be helpful if you included when you're talking about these price decks, particularly the U.S. Price deck or forecast, you at least show alongside it, I know it's volatile, but just sort of where the transactional curve is, I know it's not a forecast, but just where the market is transacting as far as oil or gas. And what I mean --

DR. MEDLOCK: In terms of the forward or something like that?

MR. WAYNE: The forward curve, right.

DR. MEDLOCK: Yeah.

MR. WAYNE: And why that's important, and I see it particularly in the Rockies where I cover it extensively is, you know, producers will hedge, they hedge a large amount of their gas production, and depending on the price level and the shape of that curve, will influence their cost and how they produce. So I think just as a data point at least just always benchmark your forecast against where the market is transacting is helpful and insightful.

DR. MEDLOCK: I think it’s a fair statement to make, but it’s also important when you do that sort of benchmarking to understand liquidity in the curve and it pretty much evaporates after about three years, so a lot of what you see in terms of like what the NYMEX will put out there in terms of what those prices are actually listed, you’ll see very little liquidity and a lot of it is just based on a trend analysis over the previous three years. So I think one of the things to do if that’s going to be the case is to make that point and maybe perhaps actually put those liquidity markers which are available on the NYMEX from the CME on a daily basis. It’s an important point, very important point.

MR. RHYNE: I’d like to ask one more question and, actually, this question can help move us, I think, away a little bit from the model itself. The model is constructed on assumptions of economic behavior and it’s very strong in terms of that approach, but that’s not the only type of behavior that drives participants, specifically developers and large scale consumers. It would be interesting to find out from our panelists if there are any roles for strategic behavior that may deviate from the business as usual. And I'll give you one example of that. The development of LNG export capacity as a type of, say, hedging strategy to establish some cost minimization approach in a future looking – it's not a pure economic strategy, and yet it could be a strategic strategy. What do our panelists think we may see in terms of deviations from this business as usual kind of economic approach?

COMMISSIONER PETERMAN: Well, as they are thinking about that, I had a clarifying question about LNG exports and, just to make sure I understand how it's used in different scenarios. So I see in our high price scenario, there is LNG export in that, and is that because the high prices make it economic to invest in LNG? Or is the causation reversed, that somehow --

DR. MEDLOCK: No, actually, yeah, that's a good question. The way that's actually modeled is you get a bit of a price uplift -- and there are other things going on here, right, that help try that sort of high price case, but there's an explicit assumption with regard to the volumes that would be contracted for delivery outside of North America from North America because, in the Reference Case, there are no existing contracts. There are some sort of non-binding agreements with regard to the Cheniere facility that's been proposed for export in the Sabine Pass region in Louisiana, with consumers -- potential customers in India and Europe, Spain in particular and Portugal, but none of those are actually binding commitments, and so in the Reference Case, you don't actually have that hard coded as a contracted delivery.

One of the things that is actually done in the high price case is those contracted deliveries are assumed to be binding, and so what you actually see is, in effect, an increase in demand for North American gas, which is what helps to lift price a little bit in North America.

COMMISSIONER PETERMAN: Thank you for that.

DR. MEDLOCK: Sure.

COMMISSIONER PETERMAN: So, Panelists, do you have any responses now to Ivin's question?

MR. WILDER: Scott Wilder, Southern California Gas. I can say a little bit, although we're really a distribution company and not involved in the actual gas production, but a little bit related to what was just discussed, you know, in the absence of long term contracts, the generally like multi-billion dollar expense of building an export facility, you would have to have some kind of incredible strategic interest to do that, to go against the current economic situation, or if you had an economic outlook that was not favoring that, if you were going on kind of a pure potential strategic play. And I hope I'm understanding the question correctly.

COMMISSIONER PETERMAN: So you're saying that one wouldn't do it without the economic interest?

MR. WILDER: I think you would want to see the economic interest either there or be fairly sure of the probability somewhere five years or so out in the future.

DR. MEDLOCK: Yeah, just to sort of reinforce the point that Scott is making maybe, even the CEO of the controlling -- it's Apache for the Kitimat proposal, for exports out of Kitimat in BC is on record within the last six months as saying that one of the things that will really sort of drive the full scale development of that facility is the securing of long term contracts on an oil index basis with customers in Asia. And certainly that is appearing to be increasingly likely, but to date those contracts are not in place. And so, in terms of the Reference Case, you can't really go ahead and make an assumption that they will be, which is why we do scenarios, to sort of make that assumption that ultimately they are, and try to understand what that means, but sort of building -- you're absolutely right, it is a multi-billion dollar sort of venture -- building that at risk without that sort of contract underpinning of the development, you're going to be hard-pressed to find a bank that will underwrite that in sort of any case, so you have to have a really large player that can do it purely on sort of an equity basis and, even then, I doubt there are many CEOs that would take that risk. So, again, that's why we have to do it on a scenario specific basis.

MR. WAYNE: I was going to say that –- this is George Wayne again -- my only comment with regards to that question is, on all the modeling that we do at El Paso Corporation is we assume, you know, an economic dispatch, I mean, particularly in the long run. And our investors, our company are looking for some kind of an economic return. I mean, we realize that there is irrational or gaming that goes on in the market, you usually see that on a day-to-day or over a very short period of time; again, in the long run, we do assume rational economic recovery of capital. So, I guess that's probably really my only comment.

MR. WOOD: This is Bill Wood with the California Energy Commission. With regards to things that could impact the natural gas market that are not economical, several come to mind, some of which we have included in our scenarios, but basically it's areas in the area of regulatory things that could happen like do you reduce coal use in power plant generation, or don't you? Do you have more strict RSP, or do you reduce it? Do you allow fracking to occur for the development shale or other resources, or don't you? Do you restrict certain kinds of resources because of sensitivity in the particular areas, or do you open up the resources? All of these things can have an impact upon either the demand side or the supply side that can impact in the market, that aren't strictly economic. And there are probably more kinds of regulatory things that I haven't mentioned here that could also have those kinds of impacts. And I said some of these we have included in the scenarios, but not all of them.

MR. WAYNE: Well, I guess the only -- for all of those particular points you're making, I guess we do try to model or look at some kind of an economic justification for them to go one way or the other with regards to fracking, with regards to a lot of these Renewable Portfolio Standards, greenhouse gas issues, the like. We always come down to some kind of a price point, a threshold that will move it one direction or another, so we do -- we still try to base it on some kind of an economic rationale.

COMMISSIONER PETERMAN: I have a quick question for George since you're talking about that. When you do that analysis, you have the existing statutes or what's in the pipeline, but then do you look at extreme cases? Do you look at RPS of 40 percent? Fifty percent? Even though those aren't explicitly on the table now?

MR. WAYNE: Yeah, we do run, as you all have done various scenarios or sensitivities to our base case, we call it, to understand what the drivers of those particular changes might be. And, I mean, I've looked at all your sensitivity and base cases, those all seem pretty reasonable and, again, very good things to do to be able to test your Reference Case.

MS. VU: On the shale gas development from the question, what I believe is the industry -- what they push for is prudent development because it's a brand new technology and also a lot of new production area has different geography, so it impacts the local community differently. So there are issues like recently in the *Wall Street Journal* talking about water contamination, possibly some chemicals from the fracking affecting the water use, all of that needs to be addressed so that there would be a public acceptance of the technology and the development of the resources. The resource base is so large, so therefore recently the NPC, the Natural Petroleum Council came out with an assessment of the resources, as well as the emphasis for best practices and also prudent development, sharing the best practices and proceeding with development in a very prudent way. And I think there are laws from different states enacted to make that happen.

DR. MEDLOCK: I'll just make an additional comment on that point. A lot of the stuff that is happening with regard to assessing the viability of shale in the face of some of these concerns is happening in real time, and so that's a very important sort of point to sort of take on board when you think about the modeling process because a lot of what has been done to generate the Reference Case and the scenarios has been done over the last six to nine months, in particular with the cases that are being presented today, within the last six months. And so, things that have sort of been reported out by the NPC, in particular, the study that was just released, was actually just released in the last week, so you will not necessarily see a sort of full incorporation of a lot of that consideration in, or a lot of those sorts of studies in what is being discussed today. And quite frankly, from a modeling perspective that's one of the most difficult things to try to sort of keep your head around because you're being asked to stay on top of things that are happening in real time very very rapidly, and on the policy front very very rapidly. And it's not always possible to predict exactly where sort of that's going to swing. So I think in the scenarios that have been developed there was quite a bit of trying to understand where that might actually go, but you know, as with anything in the policy arena, it's very very difficult to predict that outcome.

MR. TAVARES: Okay, I have a question for George. I know, George, you do a lot of the modeling at El Paso on the natural gas. Do you see, you know, the Reference Case -- and again, we are not putting a special emphasis on Reference Case –- but how do you see your prices, what kind of a stream of prices do you have in your modeling compared to what we have here on the screen? This is in 2010 Dollars per dozen cubic feet.

MR. WAYNE: Yeah, in our modeling we really, with respect to the U.S. prices, our price forecasts, or "price deck" that I like to call it, is in general higher, probably -- particularly when you go further out in the curve, a couple of dollars higher than what you have in your Reference Case. Also, we don't have that up there, but our assumption as far as oil-gas spread, at least in the early part of the years, the next five years, I call it a "medium term," our oil-gas spread assumption or ratio is also wider than what you all show. But it's interesting because, in general, the output of your model is really not so much different than ours. You know your high level themes as far as what's driving demand growth across the U.S., your assessment of supply and production, your assessment of even in the State of California, you're going forward projection as far as the California demand growth, is really not that far off from ours, even in light of the fact that our price curves diverge, again, more toward the back end, if that's helpful.

MR. TAVARES: Okay, yeah. Thank you. Anymore questions? Yes.

MR. KLATT: Hi. My name is Greg Klatt and I represent Transwestern Power Plant Company. I just have some questions regarding the Reference Case. The first is that – and I don't know if you're prepared to get into this level of detail, but I just wanted to go ahead and at least get them out there. The reports Reference Case projects a utilization of 37 percent on a segment of the Transwestern Pipeline in the year 2022, I think it's the West of Thoreau segment. And that just seemed like a very dramatic reduction and utilization and I was hoping you could shed some light on what the drivers are behind that in terms of the Reference Case.

DR. MEDLOCK: Yeah, that's a very good question and it's a very specific question, particularly when you sort of ask anybody to project pipeline utilization in a particular year, but one of the biggest drivers of the outcome that you're actually seeing there is what's happening with regard to demand for natural gas, west of Thoreau, in particular. So in the California market largely and that really falls primarily on the assumptions regarding Renewable Portfolio Standards. And the sort of other things that are more subtle that haven't been discussed, but I think that will be later today by some of the CEC staff with regard to assumptions around efficiency improvements and other things that definitely have a high level impact on gas demand. So that's largely what drives that particular result.

MR. WAYNE: This is George Wayne again and, again, that is a very specific question, I know we'll probably get to those more granular questions later on when you're going through your Reference Case detail or your scenario details. But like with the Ruby Pipeline, you show a very low utilization also for that. Now, in going forward, just for an update, I mean, the Ruby Pipeline roughly at 62 percent and growing utilization rate, and you have it, I think, in the low 40's and, again, in our modeling, we do show that dispatching higher really throughout the 10-15-year period, and also in our modeling of all the pipelines, even Transwestern and others, we see higher utilization rates than you’re showing, although again it’s interesting to see your overall demand outlook for California as far as gas is again pretty much in the ballpark, or fair away of what we’re showing, so there is maybe a little bit of disconnect at how that’s happening, but the output seems reasonable, but some of the inputs and more granular steps, there seem to be a few disconnects, but I’ll wait for --

COMMISSIONER PETERMAN: Well, I’ll just interject, George, I think this is the time to cover the Reference Case, and so if you have specific questions, please bring them up and also, being aware of the time, if they are all not covered or answerable at this point, please provide them in written comments because it would be great for us to get that feedback.

MR. WAYNE: Well, I had that general comment, I just see sort of like, again, sort of low utilization rates a lot across a lot of these pipelines, particularly coming up from the Desert Southwest, that is Transwestern EP&G and even Kern.

MR. KLATT: Greg Klatt again. Could I just ask you a question about --

COMMISSIONER PETERMAN: I want to get that question answered first, though, pardon me, Greg. So could you comment on that, Dr. Medlock just around the relative low utilization rates on those lines? Thanks.

DR. MEDLOCK: No, absolutely I can offer up an answer. A lot of it has to do with the manner in which, quite frankly, California demand is met. You can do things in the Reference Case, in particular, that will sort of change the outcome. You know, it's kind of hard to make direct comparisons between what is being done with regard to the Reference Case or the base case, in particular, in the El Paso consideration vs. the CEC consideration vs. the SoCalGas consideration because, you know, you really don't know at its face how the assumptions compare. I think the comment about demand being similar is important to understand, and so what that leads you down the path of trying to understand sort of beyond that point is, if the demand projections are the same, how do projections with regard to capacity utilization on Ruby, on Transwestern, on EP&G, on GTN, how do those all compare? And what it sounds like largely, the big swing source of supply with regard to understanding the differences in the assumptions is going to be primarily Canadian supply. And you know, it's hard to say whether or not El Paso has the same assumptions as SoCalGas, as CEC, as Rice University, with regard to the cost of supplies that will be coming out of Canada, relative to the Rockies, relative to the U.S. Southwest, in particular, so I think that's really where the swing is, trying to understand --

MR. WAYNE: Well, that's a good -- I'm sorry to interrupt you -- that's a good point, but what I see, though, is relatively to our cases, particularly Canadian exports to the U.S., you are declining faster than we are, so there's less gas from Canada coming into the U.S., so again, which would mean higher utilization rates on pipelines such as El Paso, Transwestern, Kern, and others. So, again, I see a disconnect because I see less imports from Canada, but, yes, I don't see more and higher utilization rates.

MR. BENNETT: Or -- this is Lee Bennett with TransCanada -- are you taking into account the shale plays coming on, offsetting the conventional declines?

DR. MEDLOCK: Is that directed to me or George?

MR. BENNETT: Yes.

DR. MEDLOCK: Oh, absolutely, absolutely.

COMMISSIONER PETERMAN: Greg, I interrupted your question. If you wanted to ask that, as well?

MR. KLATT: Oh, thank you. Greg Klatt again for

Transwestern. This actually goes into, at least indirectly, the question that Mr. Bennett raised and that is, in terms of the sources, supplies, we noticed that for Transwestern, obviously we focused in on that, but for Transwestern, the assumptions seem to be that it was only connected with the San Juan Basin, when in reality the Transwestern Pipeline System can access Permian Rockies via TransColorado, Northwest, even Mid-Continent and Shell supply areas. Are we just not seeing that detail in there, or was it in fact the case that, for purposes of the Reference Case you just made the assumption that it was only San Juan Basin gas going through Transwestern?

DR. MEDLOCK: If that's directed at me with regard to how that is actually reported, it's probably, well, I would say it is difficult for me to answer because I do understand that Transwestern can reach back definitely farther than just the San Juan Basin supply region, but in terms of how that is actually being reported and what you're seeing in the report that you're referencing, it's difficult for me to say. I really don't know. So I think that's probably going to have to fall on the CEC staff, quite frankly, in terms of how that report was generated to answer. I don't know, Leon, if it falls on you, or that falls on Ruben, or who, but hopefully we can address that today, or if not today, later.

MR. RHYNE: So we'll definitely try and get that answer for you. I don't know that we can guarantee that we'll have it for you today, but we will certainly address it to you.

MR. WAYNE: One general comment, I do plan on leaving with you at least the slides that you provided as far as your Reference Case breakout. We did a side-by-side comparison, at least our forecasts along with each one of those criteria, and I'm going to leave that with you all so you can use it at your liberty.

COMMISSIONER PETERMAN: I appreciate that, George. And also, I appreciate your insight into, whether now or later, into fundamentally what the price implications from the assumption of the lower utilization of the gas lines you identified; being in a regulator position, I'm trying to take it to the high level and think, okay, how does this impact exactly what we're looking at? And so I appreciate your thoughts about how much that will move things, or whether it is more of a technical concern.

MR. TAVARES: Okay, any other questions, comments?

COMMISSIONER PETERMAN: And Dr. Medlock, do you have any additional statements you want to offer now?

DR. MEDLOCK: Other than the fact that I think a lot of the feedback is welcome and I think very good, there's not a lot with the exception of, you know, it's important to understand that, if we're going to focus on a discussion at the end of the day about capacity utilization, you know, and sort of one particular case vs. another, and one particular set of sort of scenarios that have been developed by either El Paso, or SoCalGas, or CEC, or TransCanada, or you know, so on and so forth, it's important to understand if we're focusing on capacity utilization, in particular, that we need to also compare what's the baseline assumption with regard to capacity itself and demand, and make sure that we're all on the same page there if we're going to go forward with a discussion about capacity utilization. And I think that's probably a little bit more difficult to do, it's more of a longer term kind of answer, if you will, than what we can probably address in one afternoon. So, that's really it.

MR. TAVARES: Okay. Commissioners, it is almost 12 o'clock. If you want to, we can break here and come back around 1:00?

COMMISSIONER PETERMAN: That would be great. Let's take a lunch break and see you all here at 1:00.

MR. TAVARES: Thank you.

(Break at 11:58 a.m.)

(Reconvene at 1:06 p.m.)

MR. TAVARES: Okay, we're going to start right now. Are you ready, Commissioner? Okay. Our next speaker is Leon BRATHWAITE. He is part of the staff here at the Commission and he is going to talk about the high gas price, low gas price, and also the Constrained Shale Gas. Leon.

MR. BRATHWAITE: Thank you, Ruben. Good afternoon, Commissioners. I am Leon BRATHWAITE, as Ruben said. Good afternoon to the audience also. I work here at the CEC in the Electricity Analysis Office. I want to present to you what we are calling the "National Cases."

These cases, we are calling them the "National Cases" because they do not specifically focus on California. We are looking at the Continent as a whole; but as you know, California is connected to the rest of the Continent and connected to the rest of the world, to LNG, in particular, for the rest of the world, so things that are happening far away from here could have impacts right here at home.

So anyway, this morning, Dr. Medlock spoke a lot about the Reference Case, and I will not duplicate that presentation or the information that was provided there.

What we'll be looking at is what assumptions did we make relative to the Reference Case, what changes did we make to the Reference Case? We use the Reference Case as our starting point -- what changes did we make. And that is what I will be focused on. And then, when we look at results, we look at results in relation to the Reference Case. So I am not going to be talking about the Reference Case, even though I'm sure if you have any questions about it, I'll try and answer them and I think Dr. Medlock is still on the line. Okay.

So, before I get into the presentation itself, let me just kind of give you a roadmap of where we're going to go. First, we'll talk about the purpose of the cases, we'll talk about major policy issues that we looked at in terms of designing the cases, we'll talk about what are the national cases, then we look at a case description, we look at a general impact or price changes because that's important to the results, or the explanation of the results, I should say, then we'll look at the performance of the cases. We will look in terms of price and in terms of the impact upon the supply portfolio, and then we'll look at the difference in results, and then we'll draw some very broad conclusions. I am sure when it is over, we can come up with a lot more, but we'll see what we come up with.

Okay, so the purpose of the cases. Well, we were trying to look at what are the potential vulnerabilities to California, what are the potential opportunities to California? As you know, in terms of supply, we have 85 percent -- 85 percent of the gas that is consumed in California emanates from some source outside of California. So we were looking at what are the opportunities for California in terms of a supply portfolio. We also wanted to look at natural gas price and supply uncertainty. We also wanted to look at the impacts upon the portfolio by looking at the relevant policy initiatives in isolation, as we did in one of our cases, or in combination with other parameters. And finally, we wanted to develop a plausible range of price and supply outlook, all right? A plausible range -- please, on the line, "plausible," okay?

So what are the major policy issues that we're dealing with? Number one of course is the implementation of the Renewable Portfolio Standard, that of course is a big conversation ongoing here in the state. We're also looking at the conversion of coal-fired generation. We further looked at the environmental mitigation costs of shale development, of course another big conversation that is ongoing. But, in particular with the shale, we were looking at water use and disposal, which are causing a lot of discussion in the regulatory environment as to what we really do about a lot of the water that is being used to develop the shales. Now, I just want to make one point here. This morning, somebody said that the technology where shale development is concerned is new; a little correction, it is not new. Thirty years ago, I was fracking wells in East Texas, okay? Just note. But it wasn’t new then either. But it is a technology that has been modified and reconfigured and is now being used to develop the shales.

Lastly, licensing of liquefied natural gas for export, all right, that is something that is currently ongoing. We have Kitimat in Canada, is probably a very close to having a full export license, maybe someone in the audience can tell us what is the status of Kitimat in that regard. I just understood -- someone just told me that Jordan Cove just applied for a DOE export license. So exporting of natural gas, of LNG, will become something, will become a part of our future.

So what are the National Cases? Well, the National Cases are as follows: we had a High Price case, a Low Price case, and we had a Constrained Shale case. So what I’ll do now is try to describe to you what were the changes that we made. Now, remember, we are talking about changes relative to our Reference Case, okay, *relative*. Don't get lost on that point.

So what did we do? And maybe I should move my slide along. We removed about 50 GW of coal-fired generation, and this came from the Brattle Group analysis. We also assumed economic growth is going to be kept at about 3.5 percent -- we can call that robust. We also delayed the implementation of the RPS by an additional 10 years. This was driven by the fact that maybe at a State level we'll have some budgetary concerns about the funding for some of these programs. Then, starting in 2016, we assumed robust energy export capability. Now, just the capability, okay? That was developed and utilized at Kitimat, at Sabin Pass, Lake Charles, Freeport, Cove Point, and as I just said, Jordan Cove, which this is not in our model, but Jordan Cove just applied for a license at the DOE.

Moving along. We also assumed -- I mentioned about some of the environmental issues related with shale development -- we did assume that there will be additional costs, compliance costs, in the development of shales. So we added $.40 to the O&M production costs for the development of shales and we added $.20 for that of conventional resources. Further, we removed from development certain resources, particularly in particular regions, in Pennsylvania, in New York, Colorado, Wyoming.

As a result of that, we shrank the resource base by almost 18 percent. And on the international front, we did introduce constraints on development in certain places like Iran, Iraq, Venezuela and Russia.

So this is what our Supply Cost Curves look like. The green is a 2007 Reference Case, that's the green right here, the red is the High Price case, the case that we are discussing right now, and the blue is our 2011 Reference Case. So we see we have a pretty good spread here, this is the shrinkage that has occurred. But what you should note here, obviously, it is quite obvious, that we have a very flat portion of these curves here. So if we really and truly want to move prices, if you want to move prices in one direction or the other, you've really got to do something about this flat portion of the curve, which is very difficult to do, given the abundance of resources that we have right now.

Okay, let's talk a little bit about what we did in constructing our Low Price case. Well, we assumed that all states meet the RPS targets on time, of course this will dampen natural gas demand; we kept long term economic growth at about 2.1 percent, sort of -- you could call that probably weak economic development; we disallowed oil LNG exports as opposed to what we did in the high price case where we allowed it, we disallowed it here, we are keeping North America somewhat isolated; and we assumed technological development will occur at about 2.5 percent per year – in the Reference Case, it is somewhere around one percent, maybe slightly less than one percent. We also assume a larger resource base and we shift the curve about 5.8 percent to the right. And in this case now, as opposed to our High Price case, we allowed Iran, Iraq, and Venezuela to enter the market unimpeded beyond 2015, I believe it was.

Okay, so here we have the supply cost curves for our Low Price case. Again, the green is from 2007, the blue is our 2011 Reference Case, and the red right there, the red, is our Low Price Case that shows the 5.8 percent expansion in our -- I'm sorry, this is all Low Price case -- that shows the 5.8 expansion of the resource base.

The other case that we looked at was the Constrained Shale case. As I said earlier on, there are a lot of issues, environmental issues related to the development of shale. One of them, one of the biggest issues is the use and disbursal of water. I mean, every frack job requires in the millions of gallons, I think it's like anywhere between two and four million gallons of water. So the question then becomes where does that water come from, and after we are done fracking a well, and we have drawn the water from the well, what do we do with it? It is a very very big issue. So we tried to see if we could come up with some idea as to, in handling that water, what if there is a cost in terms of production in developing shales. So we added $.40 for shale development in terms of production cost and added $.20 for conventional resources. So the resource base in this particular case remains unchanged as compared to the Reference Case.

So before I get into the actual results, I just want to talk a little bit about what price changes do in the oil cases. Now, we designed these cases to get prices to move in one direction or the other, either high, or low, or something in between, okay? So higher prices as you know from Economics 101 will tend to depress demand and it will stimulate supply; lower prices, on the other hand, stimulate demand and suppress supply. So usually, though, it is some combination of those impacts that will occur, and it’s rather difficult sometimes to discern exactly what the impact is, or where the impacts are, I should probably say. But price changes do something much more important, well, probably *as* important, it reconfigures your supply portfolio. This is what happens. So whenever you see a price change, some resources will become attractive and some resources that were previously attractive become unattractive. So what happens is that you end up with a supply portfolio that may look different -- sometimes radically different -- than what you started with. So we will try to look at that reconfiguration of the supply portfolio as we go through the results of these cases.

So let's talk a little bit about the performance of the cases and let's focus on the Lower 48; remember, these are National Cases, okay, not California specific. So here we have the price. Now, we are using Henry Hub as a sort of national price, as a sort of gauge of prices on the Continent, and you can see prices are behaving as expected, the High Price is on the top, the Low Price is on the bottom, and the Reference Case, which is the blue line, is in between and you have your Shale Constraint case which is above the Reference Case for the most part, but it does touch it at certain points. What we have done here really and truly is to create what we have called the "Zone of Uncertainty," some people call it a "Cone of Uncertainty," but, you know, a cone is a three-dimensional object, but anyway…. We have created a zone of uncertainty where we believe it is plausible that prices could fall within this zone over the forecast horizon, we don't know exactly where, but we just say that is all a plausible zone of uncertainty.

This here measures the price differentials we use in Topock, which is a pricing point in the southern part of the state, and Henry Hub, which is our national price. What we are seeing here is that somewhere around 2013, our price differential will go from positive to negative. The question then becomes why. Why do we see this behavior? Well, I want you to think about these prices, think about Topock as a Western price and think about Henry Hub as some sort of Eastern price. Everybody with me so far? Now, Lippman Consulting, which is one of the people who provide us a very nice production database that we use here at the Commission, define what he calls the "Big Six," that is the big six shale plays, and they are the Marcellus, the Wood Ford, the Haynesville, the Barnett, the Fayetteville, and the Eagle Ford. Now, if you look at a map of the United States and look at where those shale places are located, nearly all of them, if not all of them, are located in the eastern half of the United States. So what is happening is that shale, which produces over 21 Bcf in August, most of that production is occurring in the eastern half of the United States. So that grid among the production that is occurring there is suppressing prices, and I don't mean that as a bad thing, but it is suppressing prices more in the east than it is doing so in the west. So this is why we are seeing this conversion from a negative differential to a positive differential after 2013.

Now let us look a little bit at the supply portfolio. So here we have the United States, right, the Lower 48, we have production running about 69.2 Bcf, and we have demand running about 71.1 Bcf per day. So what we can say here, though, is that we have two main demands, we have end-use demand and we have exports, which is represented right here. And we have three items, or three elements in our supply portfolio trying to satisfy that demand; we have Canadian Imports, which is bringing about --- and I'm using 2025 as my snapshot here --- which is bringing about 10.5 Bcf a day, we have of course the Lower 48 production trying to satisfy demand, and we have LNG imports which is running about 1.7 Bcf a day. Now, this is a supply portfolio in the Reference Case. Now, what happens when prices change? This is what I am speaking about when I talk about a reconfiguration of our supply portfolio.

So let us look a little bit at the High Price case. In the High Price case, we see Henry Hub prices up about 8.5 percent. We still have our two main demands, end-use demand which is up about 1.1 percent, and export which is up almost 10 percent. Now, you may look at that and say, "Well, you know, Leon, that contradicts what you just said. If prices are up, demand should be down."

Well, we are doing other things in this case, this is a case that we did in combination, we are doing other things. In this particular case, we have robust economic growth, capping at about 3.5 percent. We also have the conversion of coal, 50 GW of coal conversion to gas. So, even though prices are up, we also have end-use demand up because of the other things that we are doing within the case. So what is satisfying this demand? We have Canadian imports, which is up 25.2 percent, we have Lower 48 production, which is down about 8.8 percent. And the reason for that is because of the increased costs on shale that we have assumed in this case. But we have LNG imports coming in to also satisfy demand, and that is up about 290 percent, you know, it's a little bit up, it started off small, so it looks like a big number, but it is only 6.9 Bcf per day coming in. So what we are seeing here is that the elements of our supply portfolio are competing to satisfy the demand, that is what is happening. And this is what is causing the reconfiguration of our supply portfolio as things that were once attractive become unattractive, and things that were unattractive previously now become attractive.

Now, let us move to our Low Price case. In the Low Price case, we see prices, Henry Hub prices, down 7.6 percent, end-use demand up as you would expect 4.7

percent, no change in exports, we are not allowing exports -- we are not allowing LNG exports in this case. Demand is satisfied by Canadian Imports which is up 8 percent; Lower 48 production, which is up 3.9 percent; but LNG imports are down almost 15 percent. But in this case, you can see production is running almost 72 Bcf/d in 2025, the Lower 48 production, and Lower 48 Demand is running at almost 75 Bcf/d, and there we have all elements again and we see the reconfiguration of the supply portfolio, the elements satisfying our demand.

And if we look at the Shale Constrained case, we see that end-use demand, we see prices down 1 percent, but end-use demand is also down 3.2 percent. Well, there is a little anomaly here, well, it’s not really an anomaly, okay, prices in previous periods also affect the prices in the current period. So in this case, the previous period, prices were up actually about 3 percent, so as a result, some of those lingering effects are showing up in the current period and we see end-use demand declining about 3.2 percent. So what is happening here? We have demand being satisfied by Canadian Imports, which is down about 15 percent, you remember end-use demand is also down, Lower 48 production is down about 2.8 percent, and LNG imports are up almost 5 percent. Again, we see the reconfiguration of our supply portfolio.

So let us now look at the performance of the cases here in California, even though these cases did not specifically focus on California, but California is certainly impacted by the changes that we made on the national level.

So if we use Topock as our pricing point, we can see that we have prices, High Price on top, Low Price below, the price range in our zone of uncertainty is running somewhere about $5.25-$5.50, all the way up to north of $7.00; again, we have our zone of uncertainty, we don’t know where prices are actually going to be, but they are somewhere in there, we believe that is our plausible zone of uncertainty, if you can call it that. Now we can look at our supply portfolio. This is for the reference case here in California. We have essentially one demand, this is end-use demand. And how is it satisfied? It is satisfied by Canadian Imports, Rocky Mountain supplies, southwest supplies, and local production. When I say “local production,” I’m talking about in-state California production.

So if we look here, we’ll see our demand is running about 6 Bcf/d -- this again is in 2025 and I’m using that as my snapshot here. So we have demand at about 6 Bcf/d, we have Canadian imports coming in about

2.4 Bcf/d, Rocky Mountain is providing about 1.25 Bcf/d, Southwest is providing about 2.25 Bcf/d, and our local production, not much, just .2 or .3 Bcf/d, all struggling, all competing to satisfy that demand.

Now, when we go to the High Price case, what do we see? Well, prices are up 7.8 percent and, again, we are still using Topock as our reference price here. Prices are up 7.3 percent, end-use demand is down about 2 percent, Canadian Imports also down 9.7, Rocky Mountains down 7.4, Southwest supply, though, increases 4.5 percent, and local production also increases 28.5 percent. What we are seeing, again, is that reconfiguration of our supply portfolio that I've been stressing so far.

In the Low Price case, again, we have price is down, demand is up, and we have a variety of things struggling to supply the demand. We have Canadian imports up about 10 percent, Rockies up about 3 percent, Southwest dropped off a little bit, 4 percent, and local production is up about 30 percent. Again, all resources there competing to satisfy that demand.

In the Constrained Shale case, though, we had prices down about .6 percent, less than 1 percent, but end-use demand also down about 3 percent. Now, this is a case where the prices in the previous period is affecting our outcome in the current period. Prices were up about 3 percent in the previous period, those are Topock prices, and that resulted net downward pressure of end-use demand in this period. So what is happening here? We have Canadian imports down about 6.4 percent, Rocky Mountains down about 4 percent, Southwest supply up less than 1 percent, and local production up about 5 percent.

So let us talk a little bit about the Difference Results. The Difference Results is where we look at the entire 2005 all the way to 2030, and we are trying to discern what is going on in all cases relative to the Reference Case. So what we see here is that higher environmental mitigation cost is reconfiguring the order of selection of these resources. So, as a result, in your High Price case and your Shale Constrained case, production moves lower overall. Okay, this is production from all sources and we are looking at the difference here. And that difference is defined as a case of interest minus the Reference Case. So, production moves lower, we have a lower production in these cases because of that higher cost that we have put on the shales and on the conventional also. In the Low Price case, however, as LNG is pushed out because of the low prices, we have local U.S. production coming in, the Lower 48 production coming in, to take its place. So we are seeing that, because of the higher demand and because of the lower prices pushing out LNG, we are seeing increased production in our Low Price case.

In our shale, when you look at the difference where shale is concerned and, again, we are looking at the difference, and that difference is defined as a case of interest minus the reference case. And you see a similar pattern here. You see a similar pattern here where increased cost is pushing shale production down and, in the Low Price case we are seeing shale production because LNG is being pushed out and demand is higher, so we have more production from shales as a result of those two phenomena.

Now, let us look a little bit at the U.S. Demand. Now, in this particular case, higher prices push demand lower in the High Price case and in your Constrained Shale case. Now, in the High Price case, robust economic performance and coal conversion is pushing demand higher after 2022, which is what we are seeing right here, that of course is a zero line and we see higher demands there as a result of our coal conversion and the robust economic performance that we assumed.

Now, if you look here, this is a continuation of the previous slide, we have low prices stimulating demand in the low price case, pushing demand higher, and remember here that all the states are meeting the RPS on time in this particular case, the Low Price case, so it dampens natural gas demand between 2012 and 2022, so that is what we are seeing is that dampened effect in this particular case right in there where it is not seeing much movement on the natural gas demand as a result of the implementation of the RPS Standards.

Now, if you look at power generation by itself, in the High Price case power generation demand climbs higher as robust economic performance and coal conversion pulls in a lot more gas, and this is what we are seeing here with this case here. We see a lot of power generation is very strong, a lot of natural gas being demanded in that sector.

Okay, so can we make some broad conclusions? Yeah, we can. Added environmental mitigation costs may delay the development of shale formation, obviously, if some of the issues surrounding the development of shales, whether it is about fracking, or whether it’s about the water use, these things may cause either the delay or the complete cancellation of development of shales in some places, and that is showing up in some of the work that we have done. Price changes obviously can reconfigure our supply portfolio, I think we demonstrated that with the slide we just showed a little while ago. And as a result of the work we just did, we were able to produce a plausible range of price and supply outcomes -- remember, a *plausible* range, that is what we are aiming for.

Now, it is possible -- it is possible -- for us to go back in there, make some assumptions, and we can get a wider range if that is the desire of anyone, or if the Commissioners so choose; but this is what we have at this point in time, and this is what we have been willing to work with; if we have input that says differently, if there are other plausible inputs that we can come up with, we can easily go back and widen that range if it becomes necessary. With that, I will open myself up to any questions or comments, or anything else that you may have. Thank you.

COMMISSIONER PETERMAN: Thank you, Leon. I don’t have any questions or comments, but I am interested in hearing the Discussants’ response regarding the plausibility of this range. The assumptions seem to make sense to me, but it would be great to hear if there is anything that you think we missed, or whether you have concerns around the Low or the High end of these estimates. Thanks.

MS. VU: I have two questions. The first one is for verification. The Constrained Shale case.

MR. BRATHWAITE: The Constrained Shale case.

MS. VU: Yes. The only difference between that and the Reference Case is the environmental cost. Is that correct?

MR. BRATHWAITE: That is correct, yes.

MS. VU: So it is not as constrained as the High Price case.

MR. BRATHWAITE: Right, yes, you consider --

MS. VU: Because in the High Price case, not only do you have the environmental cost, you also have the reduction in the resource base.

MR. BRATHWAITE: That is true, yes.

MS. VU: So thank you for that answer. The second is more like an observation. The price range now in 2010 Dollars --

MR. BRATHWAITE: Yes.

MS. VU: -- now is between $5.00 and $7.00. Again, when we look at all of those scenarios, the industry, as well as the EIA, would show much larger variations, somewhere between $4.00 and $9.00 or $10.00.

MR. BRATHWAITE: Okay.

MS. VU: Right. So that is one observation --

MR. BRATHWAITE: Okay, could I respond to that before you continue? Okay --

MS. VU: And then the other observation is, in terms of demand across these scenarios, it is a very tight range again, it is 27 to 29 Tcf, right? So we are currently in about 22 Tcf of market, so we see from now until 2030 the variation in demand is only 2 Tcf, between 27 and 29, which to me is a very tight range. Another one I observe is the production range has higher variation, but relatively tight, it is 24 to 28 Tcf, so it is a 4 Tcf range instead of 2 on the demand side. The EIA from their work is 22 to 30 Tcf, just those are the observations. So, in my view, because of the supply cost curve, marginal cost curve is relatively flat for the first 600 Tcf of cumulative production, when you run through these cases, it doesn't change the price very much, as well as demand. So that is my observation.

MR. BRATHWAITE: And you are absolutely correct, that flat portion of the curve, and I think I said this in the presentation, is that that flat portion of the curve makes it rather difficult to move prices in, shall we say, a more extreme way -- not that I intend to be extreme, but you get my point. But another thing that I want you to remember here, these prices that we are presenting here are annual averages, okay? So if you look at the futures market today and, you know, it's probably up ten cents, 20 cents, 50 cents, or whatever it is, these are not what we are trying to reflect here, we are reflecting annual average prices, okay, so that is one thing I would like you to remember.

Now, as to the actual range of our zone of uncertainty, sure, we can go back and look at some of our assumptions, we can add new assumptions, and we can widen that range, it is possible to do that. The question is that, if we have an input that can give us some plausible assumptions that we can work with, we can certainly incorporate it in our future work.

COMMISSIONER PETERMAN: Leon, just following up on that, before going back and adding things to the model, I would just appreciate getting some feedback from staff and whoever comments, stakeholders, about where the key assumptions where we differ from the EIA, the EIA that would affect that upper level bound on price, it was mentioned earlier, some differences in terms of treatment about shale production, and I don’t know if there are other ones that people can highlight right now that might be a difference?

MR. WAYNE: I have some general comments. I mean, overall, like I said before, our prices for the oil spread is wider and our prices climb higher --

COMMISSIONER PETERMAN: George, sorry to interrupt, would you mind turning on your mic or bring it closer to you?

MR. WAYNE: Sorry, I thought it was on. I was just saying, one general observation about price, our prices start higher and they end higher than what you have, and pretty consistent with sort of what EIA and others are projecting. And our oil and gas spread is wider than what you all, to begin with and sort of ending with, is different. I agree with the lady to my right that your high and low and constrained cases are probably too narrow, I think they need to be maybe wider sensitivity, though you can see the overall effect better, I think, because I agree that the difference between 25 and 27 Tcf over a year is a pretty narrow range to be able to really see the effect you might expect. If I look at, I guess, the High Price national case, what I was surprised by is you have increased exports and obviously a heck of a lot more increased LNG imports; I just think not only from a policy perspective, but even speaking in economic terms, if we have a High Price environment here in the U.S., I just have a hard time imagining that we would allow exports out of the U.S. of gas, we would be producing more LNG imports possibly, but definitely more production, but I can’t imagine we would be exporting gas in that kind of scenario.

MR. BRATHWAITE: George, these are contracted flows here.

MR. WAYNE: Excuse me, Leon? Sorry.

MR. BRATHWAITE: These are contracted flows.

MR. WAYNE: Contracted flows?

MR. BRATHWAITE: Yes, the LNG exports are contracted.

MR. WAYNE: Yeah, but most of those LNG exports are -- they have options. Most of those holders have options to either take gas from the U.S. or Asian markets, or other places, and again I think from that standpoint, but also from a policy standpoint which would get in the way, I just don't think the U.S. would allow exports in a high price environment -- high*er* price environment. I know it's relative.

I think you also need to look at your Canadian imports and where I think you need to look at that is really your marginal costs for like Horn River and Montney. It appears to me you just have too much, or too rosy of a picture for Horn River and Montney Development. I mean, all the studies I've seen show, particularly Horn River gas, shale gas, is much higher marginal cost than really any of the shale plays. It's more remote, it has much higher CO_2 concentration, which is also additional cost, and that's not pegged for an import to the U.S., Lower U.S., that should probably more than likely be pegged for export if that were to occur, so it's not going to -- maybe in the worldwide supply demand balance, but it's not going to really have much of an impact in the national supply demand balance because, again, it's going to be a hard time for it to develop, but if it does get developed, it's more than likely going to be earmarked for export.

Going back to the definition of shales, I guess you have the slide up here, there are no shales in Colorado or Wyoming as far as gas shales that are going to be developed. I mean, there are oil shales, and some of those oil shales do have associated gas within, but it's de minimus, it's very small. So, I'm sort of confused by that slide because, again, there are really no oil shale gas shales to be developed in Colorado and Wyoming over the particular time frame. Again, there are oil shales, so they do produce a little bit of liquids and associated gas, but it's de minimus in the scheme of things to have any kind of impact. So, again, I'm sort of surprised by that. So, I guess, off the cuff, those were sort of my general observations.

MR. BRATHWAITE: About a policy concerning the export of LNG, I mean, we did not model that policy, in particular, to say that, you know, "If the prices get above a certain level, all energy exports will be forbidden." We did not think about doing that. But, I mean, like I said, you know, at some point in time, we could probably look at that.

As to Colorado and Wyoming, there are natural gas production in those spaces that do have some shales, that is what we turned off. I mean, maybe you are right, I'm not going to argue the point, and maybe you are right, that is not a lot, but there is some.

MR. WAYNE: There is very very little. I mean --

MR. BRATHWAITE: Okay.

MR. WAYNE: I mean, the Rockies as a whole is 11 Bcf a day market and, again, any shales that are producing gas, or associated gas, and that is from the Niobrara and maybe some from the Bakken, those oil shale plays create some associated gas, but that might be 2 percent, 8 percent, of the total product, it's just not very much at all.

DR. MEDLOCK: No, it's very small, actually. The biggest point about this case is that the shales that were sort of really hindered the most were the Marcellus and the shale in the Pennsylvania and New York regions, so -- the stuff in Colorado and Wyoming is tiny, I mean, it doesn't really amount to much in terms of what the model output is, so….

I actually have a comment about – you made a comment about the Horn River and I actually happen to know of a couple of developments up there that are not tied to any LNG export facilities, that are tied directly to expansions of the pipeline and gathering systems and expansions of storage facilities up in the sort of northeast British Columbia area that really are targeting developments to be moved in existing pipeline infrastructure, so I actually would disagree with the comment that it's all targeting exports.

MR. WAYNE: Well, all those pipeline settlements that I'm aware of are really gathering system, maybe some short haul laterals to get gas to either the West Coast Pipeline, the Spector Pipeline, to bring it further into British Columbia, or maybe into the AECO System. But probably the bigger project is, again, building a pipeline over the LNG Kitimat liquefaction plant.

COMMISSIONER PETERMAN: Lee, I see you giving some nods back and forth, up and down, so let's hear your thoughts.

MR. BENNETT: Well, I guess our position is that we do see Horn River and Montney being developed and the flows going forward, though, those additional supplies are going to offset the decline that we're seeing in conventional. And we'll basically bring TransCanada -- or not TransCanada -- but the WCSB back to kind of the peak levels that we had seen, I believe it was in 2001 type time frame, so that was the reason I was shaking my head a little bit.

MR. WAYNE: Well, one good point, one I want to bring up, I think you need to include in your modeling, is the implication of -- and you can probably speak to it more -- is Transcontinental's long haul system bringing gas from Western Canada to the Eastern markets. Right now, it's very very low utilization rates, TransCanada is obviously wrestling with that and trying to rationalize their rates for long haul; once that gets resolved, because right now it's not resolved and what we're seeing is that we're seeing a very low AECO price, which is creating dispatch into Pacific Northwest, into Northern California, more favorable than it has been historically. But once that gets resolved, we expect more gas from Western Canada to move to the premium East Coast market, leaving less gas to move down to GT and into the Pacific Northwest. So that TransCanada outcome as far as their long haul rate moving gas from Western Canada to the East Coast is probably a pretty important aspect of your Canadian modeling.

MR. BRATHWAITE: Would you then expect --

COMMISSIONER PETERMAN: Let me just ask one follow-up question to George, not being as familiar with the details on this issue. So is that fix likely to happen? Is it in the works?

MR. WAYNE: It's in the works right now, yeah.

COMMISSIONER PETERMAN: Okay, so that's something that one could consider as a likely political --

MR. WAYNE: Likely. It's filed at the NEB. It's filed at the National Energy Board.

MR. BRATHWAITE: So, George, we didn't expect that Ruby will replace the gas that is lost on GTM?

MR. WAYNE: Right, which gets to my earlier point, not just in the short term what I see now, but the longer term, yeah, higher utilization on Ruby and literally gas from EP&G to Transwestern, and you could bring the gas up from the Desert Southwest, as well, because of that fall-off of Canadian gas coming down GTN into the Pacific Northwest.

DR. MEDLOCK: Well, just to sort of add something to all of this, part of the reason GTN sort of has a reinvigoration, if you will, is because, yes, you do see growth in the shales, it does offset declines in the rest of the Western Canadian sedimentary basin, but you don't see TransCanada refill going west to east in the model simply because you've got so much strong production growth in the Marcellus and Eastern shale, which is really pushing back on all that infrastructure. So really, the only artery out is GTN, and that's exactly why you're seeing what you're seeing in the model.

MR. WAYNE: Yeah, I see that in the model, but I guess the question, well, pushing back is that plausible? Because I think TransCanada will lower their rate, well, they're going to move gas to that eastern market.

DR. MEDLOCK: Yeah, but you've got to remember --

COMMISSIONER PETERMAN: Well, TransCanada, you're here. Any thoughts, TransCanada?

MR. BENNETT: No, see, I can't comment on the Canadian pipe. I'm just not that close to it, I'm out of the U.S. pipelines. Sorry.

COMMISSIONER PETERMAN: Sorry to cut you off there, Dr. Medlock. Go ahead.

DR. MEDLOCK: No, that's okay. I mean, look, you've got an issue when you think about competing on TransCanada, I mean, it's not a short haul rate by any stretch of the imagination and, yeah, I agree that we'll try to maintain market share, but at some point it's a losing battle because you're talking about a lot of production on the Marcellus that is high in liquids. I mean, they're talking about trying in the State of Pennsylvania to expand NGL takeaway capacity and be able to move all those liquids, and that's what is really driving a lot of that production, which really lowers the marginal cost of gas produced there. So you're talking about trying to compete into a relatively low cost environment and it's, you know, I'm basically just describing why what you're seeing in the model is what you're seeing, and I think there's a lot of information on the ground that really supports the kinds of trends that are turning up, so….

MR. WAYNE: The other aspect, you mentioned the flipping in 2013 of the Topock to, I guess, Henry Hub basis. I don't foresee that either, it has never happened historically except maybe during the California energy crisis, at least in our model, and we certainly don't see that going forward. I mean, you look at the -- obviously there is some -- obviously more gas produced on the east, but still the majority of your gas is being produced in the western half of your market. Incrementally going forward, getting more in the East, but still not compared in an absolute basis. There's still more gas being produced in the West, even with the Marcellus growth. And then, what's going to absorb all that growth in the East is you've got, obviously, population growth, you've got the majority of your coal conversions that are happening are in the Eastern Interconnect, in the Southeast, that's where it's going to absorb a lot of that gas. And then also they have, particularly in the Southeast, Renewable Portfolio

Standards, unlike the West where you can look at wind growth and development, you've got solar, geothermal, and other renewable portfolios to be able to lean on, and to be able to supplant demand, and you don't have that luxury in the Southeast. So I guess my point is, even though you may have some incrementally more gas being developed in the East, it's going to be all absorbed and they're going to still need to move a lot of the Western gas to the Eastern market.

MR. BRATHWAITE: But you don't see any changes in the differentials is what you're saying?

MR. WAYNE: No, we don't see a deck kind of flipping of Topock to Henry -- Topock will remain below Henry Hub.

MR. BRATHWAITE: Okay. Ken, did you have any comments on that?

DR. MEDLOCK: I mean, the point he is making about where the coal substitution is going to occur, that's actually modeled, it's very explicit, actually, in the modeling, so there's nothing that we haven't accounted for on that front. In terms of load growth, the largest projected load growth from just outright population increases is in the West. The three fastest growing states in the Union are actually in the West, so you have to keep that in consideration when you're thinking about total power gen demand, commercial and residential demands, etc. So, anyway, it's a debate worth having, but these are issues that we've tried to capture in the model.

COMMISSIONER PETERMAN: I think George here internally had a question – no, George or Greg? Tell me.

MR. KLATT: Greg Klatt for TransWestern.

COMMISSIONER PETERMAN: Yes. What was your question, Greg?

MR. KLATT: Thank you, I'd just like to build off of the discussion that we've been having, two points first in terms of what Mr. Wayne said about Topock being below Henry Hub, that's -- our analysis has that same result going forward and also having Malin go up. And the second thing is that -- a question, actually for either Mr. Brathwaite or the doctor, is to what extent, or did you take into account the variable transportation costs in doing your modeling about which way gas will flow and which lines or corridors will be utilized at what levels?

MR. BRATHWAITE: Well, we do not presuppose the utilization rates, everything is done through economic dispatch.

MR. KLATT: Well, I understand that, but in terms of modeling your economic dispatch, to what extent – or did you take into account the actual transportation rates on the different lines?

MR. BRATHWAITE: Well, we have differential rates on all the lines.

DR. MEDLOCK: Yeah, the rates on the lines are the FERC filed rates.

MR. BRATHWAITE: Yes.

DR. MEDLOCK: And there is also discounting allowed so you can discount all the way down to basically covering variable and demand charges. And when you're at full capacity, you're running up against your max rate.

MR. KLATT: And just to clarify, did you use the then current rates, the rates as of when you did the modeling? Or --

DR. MEDLOCK: Yes.

MR. KLATT: Okay. Thank you.

MR. BRATHWAITE: Which I guess, Ken, we could say rates as of January or late last year?

DR. MEDLOCK: It would have been late last year.

MR. BRATHWAITE: Yeah, okay. Okay, thank you, everyone.

MR. TAVARES: Okay, thank you. That was a good discussion. Our next speaker is Ross Miller. He is part of the staff and he is going to be talking about the California High and Low Demand Cases. Ross.

MR. BENNETT: Before you start, I'm actually going to have to leave, I've got to catch a flight, but I wanted to thank the Commission very much for having us. We appreciate the opportunity to come before you and to provide our thoughts and comments.

COMMISSIONER PETERMAN: Lee, thank you for your participation and your comments, and look forward to seeing you, or at least hearing from you on the phone at our next workshop.

MR. BENNETT: Great, thank you.

MR. WAYNE: And Commissioner Peterman, I also have to leave, but I do appreciate the opportunity, El Paso appreciates the opportunity, and I think this is a great forum and a great start to you all building a solid foundation.

COMMISSIONER PETERMAN: Well, George, thank you once again and I appreciate your detailed review of the assumptions, and I think you've provided some good insights that we'll take back and, if you have any comments on any of the other sections, please don't hesitate to share them with us. Thank you.

MR. WAYNE: Thank you.

MR. TAVARES: Just for the record, George gave me a comparison of the outputs -- our outputs and their outputs, and he's going to send me an electronic version of this comparison for everybody to see.

COMMISSIONER PETERMAN: Well, thank you, George. Then you really can go now.

MR. MILLER: This is the point of the staff presentation that gets away from any expertise in the natural gas systems. I'm Ross Miller and I work in the Electricity Analysis Office, so I'm just disclosing I'm not an expert on natural gas. My role has been more focused on the overall purpose, scope and design of the Gas Market Assessment, in general and hopefully explaining how that effort can actually be useful and maybe even used.

My presentation is briefly going to discuss the organizing questions, the framework for providing useful information and the key drivers of gas demand that we focused on in the two cases that I'll be discussing. I'm going to describe those cases which were specifically to explore the effects of changing Reference Case assumptions about California gas demand, to make it either higher or lower than the Reference Case. And then I'll discuss the World Gas Trade Model and I'll actually spend more time on what we're calling Post-Processing Results for all the cases, including the National cases that Leon and Ken discussed earlier.

In Commissioner Peterman's and Ruben's opening comments, you both touched on the issues this slide discusses. I'll elaborate a bit more because they provide both the rationale for choosing the cases that we built and are key to understanding how the results might be useful.

So obviously the real world activities that the model seeks to represent are fundamentally characterized by a high complexity, many alternative options for actions which this presentation will focus on those that go on within the electric generation system and affect gas demand by that sector. And, of course, deep uncertainty about all of these interactions. And not only do these affect the gas market activities, but also electric generation and other related energy markets like transportation.

So the bottom line of all that is our estimates really have to be taken as conditional estimates. We've had a number of people already comment that they would expect to see something different and, as Ken tried to do, if you trace that back, it might be because they have a different input assumption than what we used, and that's basically how models work. If they are all conditional estimates that you really have to measure not only how the models are working, but how different are input assumptions, and it's those two things together that you start to understand why the output is different.

Even if we could make accurate predictions of the future market -- I'm sorry -- assuming that you can't make an accurate prediction with any model, as Commissioner Peterman started, we still have to make some assumptions about the future when we are making specific policy decisions, whether it is a decision about how cost-effective an energy efficiency program might be, which assumes making some presumption about the avoided cost which in California since natural gas is the marginal supply to electricity will imply some assumption about natural gas prices. So what you do, that's why we're running models. Running models is a good way to understand how the different market outcomes could occur in the future given different conditions.

I'm going to back up one more. So we could present one case. The danger there is that it might be either too rosy or too pessimistic view of the world, and basically you'd be introducing one-sided bias. So the whole strategy of producing a number of cases that have plausible input assumptions is so you can cover against that bias. Basically, I mean, even if you could predict what case would be most likely to happen, other cases could still happen and they could have negative consequences, so you would still want to know what those might be. I mean, if you're playing craps, you know that rolling a seven is the most likely outcome, but I don't think that everyone goes to a casino every month and bets their whole paycheck on one roll of the dice. I mean, it's basically that straightforward. So this shifts the focus of our discussion to gaining a better understanding of what the underlying drivers are and the uncertainties that are inherent in our trying to predict what the future states of those drivers will be, and then that working through our understanding of the relationships in the gas market that are imbedded in the model to get the results. So having a better understanding of all of this is what allows us to make more robust decisions, which are basically decisions that end up with satisfactory consequences over a wider range of future conditions that actually end up happening.

So these questions were in Leon's presentation. These are the organizing questions, why we structured the cases the way we did. And after writing this slide, I realized there is kind of an inherent bias, even in the way this slide is constructed, the way I've basically had the implied assumption that high gas prices and high gas demand lead to vulnerabilities, whereas low gas prices and low gas demand lead to opportunities. Depending on what metrics you're using, low gas prices and low gas demand could lead you to vulnerabilities; for example, if your analysis is excluding externalities and public goods, then you may come to the wrong conclusion about what's an opportunity and what's a vulnerability.

But the high and low approach is basically to give the decision maker the information so they can consider, "Well, what if we make this decision assuming gas prices are high?" They turn out to be low. What are the consequences of that? Or, vice versa. Or, "What if we make a decision assuming gas demand will be high and it turns out to be low?" What are the consequences of that? And vice versa. So basically we want to be aware of what the potential consequences could be of our particular use in a decision of any of these estimates or forecasts, whether it's a gas price or a demand level. So we're really not stuck trying to figure out what is the most likely market outcome. We actually have the option to think about what regret might I have if I use one number versus another, which is a defensible approach if no one can defend one of the forecasts being more likely than any other to actually come true. In a lot of cases, that's the position we're in: we can perhaps narrow a range, but we can't get rid of all the uncertainty.

So really, the question we end up asking ourselves is, you know, given the information all these studies provide about potential outcomes, what really is the most prudent number or quantity for me to use and what are the potential consequences of my using that? And so, I think it follows that different users of these forecasts, besides having different purposes which lead to different potential consequences, they all have different levels of risk tolerance for the risks inherent in their use of the numbers, so you can probably justify different people using different forecasts for what they're doing.

Basically, these are the drivers that we focused on in the California High and Low Gas Demand cases. Economic Condition is a key driver. The rest were largely focused on the policy drivers that are basically aimed at the electric generation, demand, resource mix, or efficiency of generation. Everything from energy efficiency programs, both for electricity and gas, renewable generation programs from the RPS to distributed generation programs, combined heat and power, all act to decrease electric generation gas demand. On the other side, you've got transportation, electrification, shutdowns of coal and nuclear power generation, all act to increase electric generation gas demand. And of course, those all interact and some run counter to each other which, besides trying to make an estimate of the future state of any of those individually is difficult and fraught with uncertainty, trying to figure out the ultimate outcome of the interactions of all these things just makes it more complicated.

I'm going to quickly go over the input assumption changes we made to the Reference Case in order to get the High California Gas Demand case. The changes are dominated by an increase in gas-fired electric generation, either to meet higher electricity demand growth, to replace electricity from our state's two nuclear power plants, which we assumed were not relicensed, to make up for the assumption of a slowing renewable generation development, and to serve a slight increase in electric vehicle charging. We also had, not related to electric generation, but we also added in some direct natural gas transportation to this case.

Okay, I'm going to note here, but I'm going to wait until later in the slide show that we made an error in execution of these changes when creating this case, so the results that are in the Outlook report and in this presentation are the results of changes that are actually different than this, and I'm going to explain what the difference is. And you know, not to keep you in suspense, it's not a major change, the gas demand for this case, if we had executed as described here and in the report, would be about five percent higher in 2017, eight percent higher in 2022, and about 13 percent higher in 2030. That doesn't sound like a lot, but it's a big system, so when later I talk about the differences between the cases, you'll see the numbers get to be a little bit bigger. And, well, from now on for reasons I'll make clear later, I'm going to refer to this error as a learning experience. [Laughter] I told you I hadn't worked in gas before, so I've learned a lot in addition to this little learning experience.

In the Low California Gas Demand case, we took a similar approach. The assumption changes in this case are really dominated by accelerating renewable generation, at both central station and distributed generation facilities, which generally displace gas-fired generation. I don't think I listed -- oh, I list it here -- there was a slight decrease in the --- I should make a distinction here, in this model the overall rate of growth of California electric demand is not the GDP, which affects the whole economy, this is a sub-estimate, which we had built into the model, where we can mimic either additional energy efficiency, or economic growth affecting demand. So you can think of this as a slight change to the amount of energy efficiency, without expressly labeling it that way.

Well, probably some of you are wondering if we had a learning experience with this case, too, and I'll have to say we did, but it was a much smaller effect and it really doesn't affect the results anymore than about one percent, so I'm not going to complicate the presentation by providing corrected numbers for this case. So I guess we didn't learn as much on that one.

Now, this slide is labeled Input Assumptions, so I wanted to make clear that that's what it is. The shaded area are the exogenous input assumptions that we made about electric generation in California, and those fed into the econometric analysis, which is again still not in the World Gas Trade Model. There's an econometric analysis that estimates what the gas demand for electric generation is, and those were the unshaded numbers at the bottom of each array for 2017, 2022, and 2030. So the colored areas are input assumptions for the econometric modeling, the uncolored area is the output of that, and that is the input to the World Gas Trade Model. And that, I think the term has already been used before, that is called the Reference Quantity of Demand because, once you put that into the World Gas Trade Model, the equilibrium model will solve for a final demand at a price of equilibrium, showing the effect of price elasticity of demand, so the final demands end up being different than these inputs.

So just to give you an idea, at this stage of the assumptions, the percentages I gave you before still apply, and it only really applies to the middle column, the High California Gas Demand. The 2022 figures for Gas Demand should be about eight percent higher, and the 2030 figures should be about 13 percent higher. Now, the reason we didn't re-do all these slides is we would have to re-run the World Gas Trade Model to get the actual corrected output for the High Gas Demand case and we didn't have time to do that, so later I will be giving an estimate of how those final demands and the other metrics that are derivative of that have changed, that's all based on this estimate and not the model output.

Effectively, what we ended up doing and why I'm calling this a "learning experience," is we kept track of the story that went along with making our changes to create a case; well, it turns out that the High Gas Demand case, we made a change that was effectively the same as just removing the two nuclear power plants, not the other things we wanted to do. We made about 60 percent of the change we had intended and because we contract through that, effectively what we end up with is another case, and it ends up being an incremental sensitivity case which actually turns out to be useful, as long as we can imagine what the real output would look like for the High Gas Demand case, which I'll give you a hand with this handy laser pointer.

So this is a diagram of the output of the World Gas Trade Model for Gas Demand in California and for all the cases. So this is the case now that actually reflects just taking out to two of the nuclear power plants. And so the case that matches the description of the high gas demand case would be up here, so that would be the outlier as far as gas demand.

Now, this is a table we put together that basically creates some very rough estimate metrics other than gas demand -- I'm going to go back to this -- I told you I'm not a gas expert, so I look at this and I think trillion cubic feet, and it's just a big number to me, I'm not really sure, I know it's more, I know it's less, so I'm trying to provide some extra sense of the significance of these numbers, so we just decided to come up with some other metrics that are either policy relevant or more intuitive to people, I guess not that I have anymore sense of what it's like to have millions of dollars, but I deal with that a lot more than I deal with trillion cubic feet, so I think I have a little better sense.

So again, in the column for High Gas Demand, those numbers would all be slightly different. The gas demand numbers would all be those percentages -- five, eight percent, and 13 percent higher, and so would all the effects, it’s basically multiplicative. Where you get a little larger sense of the impact of this change is where you just look at the effect it had on the differences among cases, which I’ll get to in later slides, but this is fairly straightforward. Another thing I wanted to point out is it didn’t change the relative position of the cases we intended, this high case is still the outlier, we just now have inserted an intermediate sensitivity case.

The metrics that we included on here were very simple, we just took the gas demand, multiplied that by a weighted cost for electric generation to come up with a cost for gas demand by electric generation, and the cost came out of the associated case, so since the price is an outcome of the case, that’s the one relationship in this table that is not completely linear. You would have to re-run the model to get the associated electric generation price to multiply here. The carbon emissions, the CO_2 emissions from the combustion of this gas, is simply an emission factor times the quantity of gas. And the CO_2 allowance cost is that emission quantity times --

basically what we selected was the reserve price or floor price from the AB 32 Cap-and-Trade Program that is specified in the Initial Statement of Reasons. And that would be at least as much as you could say is opportunity costs of those emissions; you might end up paying more if the dollar per ton auction cost of a CO_2 allowance is higher than what is assumed there, but at least this would be a floor.

Another thing I want to say about this is, if you have the question of what would be the best outcome in all these cases, this table does not give you the answer to that. If you think of that question being answered by a thousand-piece jigsaw puzzle, this only provides about 10 pieces, okay, so these are just selected metrics of change across these cases, it's not meant to be a comprehensive trade-off analysis, it doesn't tell you what the bottom line is. You know, for example, to get the outcome of the high gas price case, you know, someone is going to have to replace 50,000 GW of coal and that's going to cost money, and this analysis says nothing about that. So we're not trying to measure all attributes and do a trade-off. This is basically just to contribute to that overall "thought experiment," I'll call it.

So the next four slides are just going to basically focus on the differences between the numbers on this chart, just to make it a little clearer. And so this High Gas Demand case is actually going to be around here, and this is essentially taking out the two nuclear power plants.

Now, here is where I mention, if you do the math, the difference between the actual high as described in the report, High Gas Demand case, is really about 2.38, so here it's off the chart, so I didn't mean to minimize the characterization of this learning experience with five, eight, and 13 percent, because here it's basically -- this increases 21 percent from the Reference Case, the case that we described is about a 36 percent increase compared to the Reference Case.

So this, as I mentioned, it just shows you the magnitude of the dollars you're talking about on an annual basis if you were paying for those emissions at the reserve price. And to correct the High Gas Demand case, that would be, I think, about $1.5 billion in 2030, so the numbers are not insignificant.

COMMISSIONER PETERMAN: Ross, can I interject and ask a quick question? You can find it in both graphics, but with Slide 11, with the Low California Gas Demand, what is the percent different from the Reference Case? I'm trying to get a scale of it, the difference between the Low case and the Reference vs. the High case and the

Reference.

MR. MILLER: Oh --

COMMISSIONER PETERMAN: I think you said the High case was like 36 percent once we do the revised analysis?

MR. MILLER: That is basically about 25 percent.

COMMISSIONER PETERMAN: Okay. So it seems like also with the next slide, as well, that some economic value, the $1.5 billion difference in the Reference case and the High case is larger than --

MR. MILLER: That's right.

COMMISSIONER PETERMAN: And is that the trend that we see, this wider variation between the High case and the Reference vs. the Reference and the Low?

MR. MILLER: Right. Yeah, it's not asymmetrical.

COMMISSIONER PETERMAN: Okay.

MR. MILLER: And we didn't really construct the cases to be purposely symmetrical and a reference was made to EIA cases. I think the last EIA Annual Energy Outlook had 68 cases, and that's to underscore Ken's point, is to really compare the significance of differences in output across other people's work, you have to not only know how the modeling differs, but you also have to really do a very point-to-point comparison of all the input assumptions, especially since so many people are doing so many different cases. But that's where the better understanding of what's going on really comes from. And it does take time, as Ken suggested.

I can stop for questions here. I have two more slides that are basically about the last chapter on End-Use Prices and the discussion is going to be similar to this, it's basically an illustrative presentation to get a sense of the magnitude of uncertainties about end-use prices.

So this, if you notice, we don't even have identified a utility here; the main point of this slide is just to show that there is a significant difference in end-use gas price, depending on which sector you are, and the reason is it is cost of service based and the residential sector is the most expensive to serve, so it's going to have significant transportation and distribution costs that get added to the City Gate Price, which is basically the commodity and the cost of transportation to that point in order to fully recover all of the costs of that service. Commercial is the next most expensive. And Industrial and Power Gen, because they accept their service fairly close to the backbone, are not paying as much in incremental distribution cost because it doesn't cost that much incrementally to serve them.

Now, obviously -- well, it's not obvious since I didn't tell you or label this -- this is a Reference Case City Gate price. Since we have different cases, you can come up with a different end use price for each sector, for each case, and we did that and we posted that on the website, and we did that for each utility, and it's there for people to look at and inspect. But one thing we want to say about it is we took current estimates of the transportation costs and did not make any attempt whatsoever to assess what they might be going forward in a comprehensive way, and then put out all those datasets. So if you think of this as just -- this is another one of those reference points. What we did in the rest of the chapter was just to talk about, while there are sources of uncertainty about what transportation distributions costs could be, and that may be of less concern to the Industrial and Power Gen sectors because it's not really that big an additional cost to their end-use gas price, but for Commercial and Residential customers, it's something to be interested in. So we basically identified just three areas where there is some rough assessment of what the uncertainty about the future value of these costs might be and one of them was the capital investment that might be required for pipeline inspection, repair, or replacement, for either public safety or environmental reasons. In the report, we mention that either concerns about the pipeline integrity or environmental contamination of certain pipelines, requiring them to be replaced, all create a possibility that there could be some going forward costs that wouldn't be included in the existing rates.

We just did a "what if" analysis and I think we used PG&E's system, and with the billion dollars of capital investment, that ended up being about an eight percent increase in just the transportation cost component. So, if you're looking at a residential customer where that is only half of their end-use rate, that would be a three or four percent increase in their end-use rate. And we made no attempt to figure out how many hundreds of millions or billions of dollars might be needed to be spent in the future on anyone's pipeline system.

The other -- there was a debate about the Public Purpose Program Surcharge. That turns out to be a fairly hefty chunk of the residential and commercial, so we thought that was worth looking at, and that was about 11 percent of the residential transportation distribution cost and it was a much higher percentage of the industrial, actually.

And the last thing we looked at is basically just again looking at the cost of CO_2 allowances since ultimately those costs have to be recovered from end-users. And this was, again, at the minimum floor price, this was about a five to 10 percent of City Gate prices, well, five percent in 2012 and about 10 percent in 2030, just to give you an idea of the magnitude.

I think I'll end it here and if there are any questions, I can entertain them, or -- we've lost Ivin.

COMMISSIONER PETERMAN: Ross, I have a follow-up question. Is this the first time in the IEPR, or at least relative to 2009, that we've modeled the forecast End-Use Gas Prices?

MR. MILLER: No.

COMMISSIONER PETERMAN: This is not, okay. I just remember we had some discussion around the value of getting feedback about this analysis and how can it be utilized going forward, and so I particularly would appreciate Scott's feedback on this and some of the assumptions raised and the uncertainties identified.

MR. WILDER: Well, I have a related question. Scott Wilder, Southern California Gas. Ross, I guess I'm not quite sure, but in your California High and Low Demand scenarios, are there differences in gas price assumptions?

MR. MILLER: In the High and Low Gas?

MR. WILDER: Yeah, the High and Low Gas Demand --

MR. MILLER: Not in -- each case has an input reference quantity price assumption for oil, for gas, for coal, and even electricity. But each of those cases ends up having its own final gas price. So if the question is, is it significantly different than the other cases, it's not significantly different than the reference case because moving California Demand really isn't a big enough driver of national prices to get much of a movement.

MR. WILDER: Okay, I was asking more related to the input assumptions, if the inputs assumed the same gas prices for the High and Low.

MR. MILLER: Yes.

COMMISSIONER PETERMAN: Why do you ask?

MR. WILDER: Well, I'll go ahead and make a comment, it's probably related to both the national that we passed with Leon and the California would have an effect. Kind of reinforcing what both George and Mia said in a statistical way, looking out at least a decade or more and assuming such a narrow range, I did not do this for the Topock California Border Price, but I did go back when I looked at this last week and just looked a little bit statistically for the Henry Hub National Price, and if you go back to even just the past 10 years, 2001, you end up looking at real 2010 prices and the volatility in the last decade, and you end up with a standard deviation that is over $2.00 per million Btu. And if we just, for instance, go out 10 years to, say, 2022, we have kind of a national case, and I think it would apply to California, as well, where you can add say $.20 per million Btu for transportation, where we have a Reference Case that is in 2010 dollars out in 2022 of roughly $5.50, and a High-Low variation of only about $.50 on either side, so we've got a range of about a dollar plus or minus $.50. Well, if you took even one standard deviation, which statistically would exclude about a third of the possibilities for normal distribution, instead of $.50 on each side, you're talking $2.00 on each side, so suddenly you're talking a range of instead of five to six, you're talking a range of about $3.50 to $7.50. And in a real life case, you know, in the past 10 years, four out of the 10 years have seen -- and I'm talking annual average prices here -- four out of the 10 years have seen changes from the previous year of more than $2.00 a million Btu. And where this comes in to California demand is, if you just take the price elasticity, we've talked a lot about electric generation here where it may not be so important, but in the case of residential and commercial demand, where you've got certainly a lot more California residents involved, you know, instead of talking about $.50 on roughly $5.00, instead of a 10 percent variation in price here, you're suddenly talking about a 40 percent variation in price year to year, and, well, Commissioner Peterman, you said earlier in the day that one of the reasons for the scenarios is the Commission doesn't want to be surprised, and I would emphasize I think there is a real need to widen the scope of these ranges and the scenarios, particularly with the price because it affects not only the price, but it also affects the California demand and commercial, residential elasticity, you know, if you assume it's maybe .1, .2, you talk about a 40 percent change in annual prices, well, you're talking about a six to eight percent change in demand from year to year that is simply driven by price.

COMMISSIONER PETERMAN: Yeah, please Leon, come up. And thank you, Scott, for those comments. I think those are in line with what we heard from George and a bit from Mia, as well, and we'll make sure we take that into consideration. Leon was going to make a --

MR. BRATHWAITE: Yeah -- I'm sorry, I did not get the name. Scott, thank you. Scott, I do not doubt your analysis, okay? But one of the things that I will say that will really mitigate against having a wide range, and you were right, probably a wider range would be probably more duplicative or more representative of what we have seen in the past, I would not disagree under any circumstances. But if you look at the cases that we've presented, nearly every one of those cases, and you look at the supply cost curve which is probably the biggest driver in our model, they all have that big long flat portion of the curve, which was one of the things that Mia pointed out. So what I think is happening here, so why we are not seeing a wider range, you know, we could probably make assumptions that will produce one, but the thing that has happened here is that shale is coming on at such a strong level in nearly all the cases that we've seen that it's just difficult to get that wide range that you probably would expect. And like I said, maybe we could go back and, with the permission of the other Commissioners and stuff, we could turn off some more of the shales, or do some other things and stuff, and widen the range. But I think the underlying thing is that shale is such a big deal right now, it's just now in the range to what we are seeing there. Thank you.

COMMISSIONER PETERMAN: Can I ask a follow-up question on that and the supply cost curve? So, is the way in which shale is affecting or entering the results that there is such a large flat portion of that curve because there is shale built into the model, lower cost shale? Or that it is not being --

MR. BRATHWAITE: Yes, shale is added into that flat supply cost curve. If you look in our presentation and you look at the 2007 supply cost curve, if you remember, it got pretty steep pretty quick, but then once we come to 2011, where you have a lot more shale and all that kind of stuff, that curve just got flat and didn't run out until it got to I think it was 600 or 700 TcF before you started to see that upward swing.

COMMISSIONER PETERMAN: And Scott and Mia, have you come across other supply cost curves that includes that shale, but don't have such a flat part of the curve in the lower quantities?

MS. VU: As I mentioned before, the gas industry is something that is very hard to find those information on the cost side, but I do believe that, even though we have a lot of shale resources, there are a lot of uncertainties on that cost. So if we can capture some kind of the uncertainty around that, that may increase the variation on the outcomes on the price. Because I see the way you construct those cases are very deliberate and very thoughtful, so the scenarios are all right. It's the assumptions that go into the model and it comes out to be the result of the model. Definitely long-term, shale will give us reasonable prices compared to what we experience in the last decade, but to me there is still a lot of unknowns.

COMMISSIONER PETERMAN: Fair enough, so that could be the long-run, but there is some opportunity to think about a more steep curve, or at least there are plausible futures with a steeper curve in the near term that we can consider. Dr. Medlock?

DR. MEDLOCK: Yeah, I'd like to interject something. I don't know if it's possible to bring my presentation back up because I can address something that is pretty germane to this whole discussion. I presented a slide --

COMMISSIONER PETERMAN: Give us a minute to try to do that. Go slower.

DR. MEDLOCK: No problem, no problem.

MS. VU: It's at page 16 that you talk about?

DR. MEDLOCK: I can't remember the slide number, but let's just go up, it might be around there, yeah. Oh, it's going to be earlier in the presentation. It's actually the Index of Costs against the Index of Oil Price, so go up to -- I think Mia said slide 16 -- because this isn't the right one to look at. That's it right there, yeah.

All right, so forget about the blue line right now and just focus on the red and the green line. These are actually -- I mean, this is real data, right? This is the actual cost by FIC Code in the case of the green line for the oil and gas mining sector, so that's all upstream activities, and the red line is the actual real costs of well development as reported to EIA of operators in the Lower 48. And if you just look at the last 10 years, at the variation in that cost, so just go from 1999 to 2009, you can see at the low point, which would have been back in 2000, '99 to 2000, up to the high point which would have been 2008, you saw cost inflation, so that scale in terms of what happens to cost increased by a factor of two and a half, okay? So if you look at that and you begin to understand, you know, this is why I brought up the point about, you know, we talk about break-even cost and the cost of the environment, if you want to think about the variability, the potential variability in the cost environment, right, that's a different sort of exercise and there is certainly the capability to run scenarios around cyclical behavior and the cost environment. In particular, you could run a case in which you sort of assume a high cost environment in which you might assume costs look something like they did in 2008, for example, going forward. That is going to be sure to give you very high prices. And you could also run a case where you assume the cost environment is relatively low like it was in the '90s, that is going to be sure to give you very low prices. If I were to do that, you would actually get a range of outcomes that is going to match history because that's exactly what we're looking at here, okay? So one of the big uncertainties, one of the big drivers in sort of determining sort of the vertical position, the height of the supply curve, is exactly what you assume about this. So if we wanted to do scenarios where we wanted to vary that supply cost sort of environment, that is certainly something that could be done, it's just not something that we addressed at all in the cases that we've done so far.

COMMISSIONER PETERMAN: Dr. Medlock, in the context of this graph and this discussion, then, what is done to construct the supply curve now? It is to do what, to take the average or…?

DR. MEDLOCK: No, no, what you would do -- in the context of this, all the cost curves are actually developed based on data that has sort of a real vintage 2005 kind of year, okay? So if you're looking at 2008 data, you would actually have to deflate the cost data so that you could get a real well development cost data point in 2005 dollars, right?

So if you want to maybe scroll back down to Slide 42, or whatever it was, if we wanted to go from, say, a

2005 to a 2008 cost environment, effectively what we would be doing is taking this North American curve and shifting it vertically, okay? Because one of the things that happens in the real world is this curve is actually going to have some uncertainty around it. In other words, it's going to move from year to year up and down.

The horizontal dimension is pretty much defined by whatever the resource availability is and what technology is. But the vertical dimension is something that we can slide, that's just not something that we've done in the case of these scenarios because what we're trying to do is isolate or model things in a particular sort of cost environment, a particular real price environment, and so typically what we would do is we would take a stand on where the supply curve sits. And that's actually why I showed that slide before, right, about the cost environment.

Obviously, this is a huge uncertainty, right? I mean, as I mentioned, the data that I showed you in that previous slide goes all the way back into the 1950's and you can see the same thing happen. Any time there is a run up in energy prices, costs are chasing them. And so that's certainly going to be the case going forward, as well. In general, though, what we projected is sort of a mid-trend in terms of the cost environment. There is certainly going to be times when costs are lower, so prices will be lower, so certainly there will be times when costs are higher and prices are going to be higher.

MS. VU: My question to you is can you build the variability around the horizontal curve as a range of -- horizontal part -- as some range, give it some range and certainty there?

DR. MEDLOCK: Well, you can base it on the data, you could do a look-back and base that sort of uncertainty on, you know, what we know about history. The trouble is the resource set is different now. You know, those costs and the drivers of cost were largely focused on non-shale unconventional and conventional gas developments. Now, we're talking about a massive amount of shale gas that has sort of different characteristics when it comes to upstream development. So you could do that, but it's going to be, at best, a second best approximation. That's why, I mean, I told you we have a Well Economics Model, when you look at what is called the break-even costs that are in one of the slides earlier, you actually see in some of the larger shales there is a tiering of the resource. That is because we could actually identify type wells based on existing data to date, right? Where we can actually see well performance metrics and we know what it costs for access, we know what it costs to actually drill a well, what it costs to complete a well, what it costs to bring in the frack crews, so on and so forth. So we can actually come up with numbers that are reasonable estimates.

You know, going forward, I would actually argue that the risk in terms of what is going to happen to this cost curve is more on the down side than the up side simply because developers are still learning so much about this particular play that, as they move forward, and that's why I drew attention to my previous remarks to the case of the Barnett where there has been over 14,000 wells drilled and developers are actually able now to employ fewer rigs on the play and they're still producing every bit as much as they did three years ago. It's because there is a major learning by doing component in this particular play. So, you know, just to sort of I guess tie this up, one of the things that could be done is we could model high cost environment, we could model low cost environment, but you have to recognize if you're going to take that stand, you have to assume that, because this is a non-stochastic model, you have to assume you're in that high cost environment for the entire model time horizon, right? Then you have to assume you're in that low cost environment for the entire model time horizon and you're going to get very wide outcomes in terms of the actual prices that you generate in the forecast.

MR. RHYNE: So this is Ivin Rhyne. And this is actually a really good point for me to make a statement that perhaps has been inferred here throughout this conversation, but probably needs to be done more explicitly here, is that the questions we're able to answer with regard to natural gas prices and quantities, are to some extent limited by the tools and the assumptions that we used. In this case, we're using a tool that is a model that establishes an annual average equilibrium price and quantity for various regions and various suppliers. And in doing so, it washes out that short-term variability and, as Ken just kind of mentioned, this is a non-stochastic model, which kind of in English means you don't see that random variation in the underlying effects. And so, if we wanted to ask and answer questions with regard to short-term variability of prices, and its effects on demand, and they are certainly non-trivial, especially in times as these where we can see that you have short-term both price spikes and price dips. That would require a different approach, although it would certainly draw on a lot of the underlying work that has gone into this, and so it wouldn't be completely independent of this, but it would require a slightly different approach, and so the staff here are very interested in those kinds of questions, but I don't think it's kind of in our purview at this point to attempt to promise that we could give you that kind of analysis with this particular tool, or at this particular date.

COMMISSIONER PETERMAN: Ivin, thank you for that additional background. I would ask for staff to consider the comments that have been raised and, at the minimum in the final report in the Executive Summary, just to identify some of these issues again because this conversation in the last few minutes has been very helpful to me, including pointing out that we do lose some of the short-term variability or observation of that when doing this analysis, and as Dr. Medlock pointed out, if one was to answer a particular question like that, you would need to do X, Y, Z, because I think that would allow one to become more comfortable with what our estimates are showing and what they can and cannot do, and that was great additional information you shared. Thanks.

MR. RHYNE: Thank you.

CHAIRMAN WEISENMILLER: Another question I had on the retail rate side is, do we know what is in the balancing accounts for the utilities on the gas side? I assume for PG&E, it is getting significant, I'm not sure about Sempra, in terms of under-collections.

MR. MILLER: Well, I claim the Fifth, so if anyone else wants to answer.

CHAIRMAN WEISENMILLER: Yeah, do you know?

MR. WILDER: I'm not sure for SoCalGas.

CHAIRMAN WEISENMILLER: For PG&E?

MS. VU: I don't know about that.

CHAIRMAN WEISENMILLER: Okay. Yes?

MS. VU: I could ask about that.

CHAIRMAN WEISENMILLER: That would be good.

MR. COWDEN: I think another thing to focus on -- hi, Bob Cowden, PG&E. I think another thing to focus on that was kind of at the end of Ross' slides is we made a filing in August on kind of all the capital improvements we have to make on our system, and in the final it outlines over the next four years what the growth in our revenue requirement is going to be, so there is information that there could be used to I guess either do another scenario or do an estimate of what the rate increase could be, subject to however that gets run through the CPUC process.

CHAIRMAN WEISENMILLER: Yeah, that would be helpful just to know in the past forecasting retail rates that you have to look at the balancing accounts and, as you said, what the expected -- if there is any lumpy revenue requirements. Obviously you're not simply offsetting cap as depreciation in this case.

MR. COWDEN: Right.

CHAIRMAN WEISENMILLER: So it's not a static situation.

MR. COWDEN: Yeah, so we have information we can provide and comments.

CHAIRMAN WEISENMILLER: That would be good.

MR. KLATT: Could I ask a clarifying question, please? About the price assumptions, I just want to make sure I understood correctly and, actually, I think I may not have understood it correctly. Is it that for the California High and Low case that the price inputs that you used were the same as in the Reference Case? Or was it that the price inputs were the same prices as the High Demand and Low Demand cases?

MR. PUGLIA: Peter Puglia at California Energy Commission, Natural Gas Unit. The reference prices, the input prices for all the cases, are identical.

MR. KLATT: Okay. So the same exact figures for the starting point on each of the --

MR. PUGLIA: That's right. The general Equilibrium Model and econometric modeling will give you different prices in the end, but they all start out the same. As just something that has come up before, if it hasn't been mentioned in the report or the presentations as something that was changed, assumptions that were changed from the Reference Case, then they are identical to the Reference Case. Do you understand that?

MR. KLATT: Oh, yeah, that's very helpful. And I think you also answered my second part of my question, which was that, as a result of the modeling for each of the cases that those prices, the actual values would change as you run the model.

MR. PUGLIA: That's right.

MR. KLATT: So what comes out of that would be different and that affects what the demand scenarios are.

MR. PUGLIA: Right, the prices that you begin with are all the same in almost all the cases, they're identical to the Reference Case.

MR. KLATT: And then as they go through the model as different – other variables, inputs are changed.

MR. PUGLIA: Right. Then, as you know, with a General Equilibrium Model, they solve for the change in demand, price and supply at every node.

MR. KLATT: Right, thank you.

MR. PUGLIA: You're welcome.

MR. KLATT: That's very helpful for me.

COMMISSIONER PETERMAN: Just to bang this point into the ground even more, so does that mean in the

Reference Case that the output price is the same as the input price? No. Okay. I'll figure it out later.

MR. MILLER: It would be turned off for the price elasticity.

COMMISSIONER PETERMAN: Oh, okay, right.

MS. VU: So let me confirm my understanding. The historical price, that input in the model is the same for all cases, but then the model will solve for the price as an output in each scenario. Is that correct?

MR. MILLER: Right.

MS. VU: So the models solve for the prices.

COMMISSIONER PETERMAN: Yeah, that's a nice little line just to put it in the description if it's not already there because it took me a lot to get my head around that, as well.

MR. MILLER: It looks like we have a further --

COMMISSIONER PETERMAN: Hold on, Leon is getting up, everyone on the phone.

MR. BRATHWAITE: I just want to make a slight clarification here, okay? Yes, we do start with input reference prices, okay? But however, if you change any of the independent variables, like for instance you change your amount of fossil gen, or anything like that, that will give you slightly different reference prices. So the input prices on those cases should be in some cases different -- just to be clear. So, for instance, like in the High Price case, we took out the coal-fired generation, that will generate the front Reference prices. Just to be clear. I mean, I confused the matter?

COMMISSIONER PETERMAN: Yeah, can you go back?

MR. BRATHWAITE: All right. Do you remember this morning, I'll show Ken his own -- Ken showed you a series of equations, okay? And in those equations he had a bunch of independent variables. Some of those independent variables were fossil generation, is whatever, and that kind of stuff, population, all that kind of stuff and things. If for instance we change population, it will give us the front Reference prices in different quantities. But like, for instance, in our High Price case, we took out 50 GW of coal-fired. So if we take out 50 GW, that changes fossil gen, and it changes some other things, so it should give us different Reference quantities.

COMMISSIONER PETERMAN: The quantities will change, but the price input will be -- I mean, piece of NGI, you know, substitute NGIT would be the same across all of those, right?

MR. BRATHWAITE: Quantities will change.

COMMISSIONER PETERMAN: Quantities will change, but the input prices won't.

MR. BRATHWAITE: Oh, the prices we're talking about, okay, fine. Thank you.

COMMISSIONER PETERMAN: All right, so, yeah, you were right, Mia. Thanks for that wrap-up. Were there any other comments or questions on that section before we move on?

MR. TAVARES: Okay, Commissioners, now that we are clear about the inputs [laughter]…. We have our next speaker, Katie Elder. She is going to be presenting the Low Pressure case and this will show you some of the limitations that we were dealing with, especially in regards to natural gas storage because the model does not take into account -- as we have it now -- does not take into account the question of natural gas storage through the year. Nevertheless, we ran the case and Katie is going to describe what we actually did on that case. Katie.

MS. ELDER: Okay -- where is the presentation? Okay, I give up. I tried to use my special good doo-dad and it didn't quite work, so there you go. And so that means I think that that button pushes it? Okay, somebody needs to drive for me because I can't reach. Hi, I'm Katie Elder, I'm my usual normal disorganized frazzled self. I've been working with the staff on the Gas

Assessment and there are days in which they undoubtedly quake in their boots when I walk in, and other days when they're relieved, so hopefully this part of the analysis is part of them being relieved that I took on this part of it for them. Now I have control, okay. Now Ivin doesn't have to push the buttons for me because I got it to work, lovely.

Okay, so what I'm going to talk about with that little interlude there is that part of the analysis that I'm going to show you has a little bit to do with the world gas trade model results, the rest of it doesn't, and I'll explain why.

Usually, in the years that I've watched staff's assessments, and that goes back to when none of Leon's beard was gray -- I thought that was good -- a really long time ago, there has always been some sort of point at which staff brings the analysis kind of back to something that is really practical in terms of the state's ability to serve all load. And that's in some respects what this part of the analysis is going to focus on in terms of what happened, particularly as we look at the PG&E system and some of the pressure reduction impacts that we're experiencing in the aftermath of dealing with the aftermath of the San Bruno explosion, so that's what I'm going to walk you through.

In this part of the analysis, we tried to look at four general kinds of issues, one is that, in the model, in the World Gas Trade Model itself, we did do a scenario in which we reduced the capacity on the Baja and Redwood Paths, and we brought those capacities down by about 500 a day. We did that, we know that the model, as Leon has emphasized, I think Ross emphasized, Ivin emphasized, the model looks at a whole year at a time, its granularity is kind of a total annual demand, which is going to look at it flat, it doesn't give you the ability to look at any peaks or valleys over the course of the year. So we looked at this in annual mode, knowing it probably wasn't likely to show us anything interesting, but as a matter of due diligence, did it anyway to confirm that it wouldn't show anything interesting. If we were able to run the model in its monthly mode, it might show a different result. And so, because of this limitation of the model, that it's only looking at an annual basis over the course of the whole year on kind of an average day look, we did some additional analysis that I'll show you. Those additional analyses include kind of a gas balance approach looking at stacking up total demand against the capacity and the supply you've delivered over that capacity to meet that demand, and then the gas balance, you just basically look at the difference between those two, one vs. the other, the demand by month vs. the constrained delivery capability.

We also give you a look at a peak day using some data that PG&E had in the California Gas Report. We also looked at storage refill capability.

In the Pressure Reduction scenario, we changed two key assumptions. One is we reduced that backbone capacity, and there are about three different reasons why that backbone capacity, or the pressure operating on the backbone capacity, is lower and which reduces deliverability on the lines. Some of those reductions were ordered by the Commission, the PUC. Some of those are PG&E's result of its classification study and finding that some lines were misclassified, so if you correctly classify them, their maximum operating pressure should be lower, so they would flow less gas. Some of those reductions are going on as hydrostatic testing and our replacement continues, so those tend to change relatively often as that testing proceeds. As I mentioned earlier, we reduced capacity on the backbone by about 500 a day total, and so we took Redwood System down from its normal of about 2050 MMcf per day down to 1850, and we took Baja down by about 300. Those numbers were based on what was showing up on Pipe Ranger in mid to late July when we did the analysis as being available through year-end. Now, those numbers change, as I said earlier, as PG&E does the testing, is able to bring some lines back up on pressure, it changes based on what segment PG&E had to take out of service on a given day, and so you have to watch those numbers. And I think they changed again last week with Redwood coming back up to 2050, but nonetheless, we've got modeling results that looked at it being lower because that's what we were seeing at the time, and that lets us be conservative.

The other big change that we made in the model result was to turn off the capacity expansion because one of the things that the model will do, or that we had the model configured to do was if prices continue to go up and you see basis differentials grow, and our economic actors that we're simulating in the model get the signal that it would be economic to add new pipeline capacity, the model will add it. And so, given that we were constraining capacity and, if it turned out that we needed that capacity, it would be reasonable to expect that the model would see that in the form of a price signal and add capacity, which would not show us any interesting result, it would basically undo the capacity constraint that we had introduced. So we turned that off.

The end result of that is that it doesn't show anything exciting or unusual and you can say kind of, "Ho hum, why did you waste your time doing it?" Well, we did it in order to be careful and to make sure that we had the scenario covered. You see a few little annual price changes or perturbations, I'll call them, in price year to year, they're not particularly consistent one year to the next, they're small on a percentage basis, they don't occur just for California, they occur for Henry Hub, as well, and so it's something that's going on in the model that's not specifically germane really to exactly what's going on in California.

The other thing that you see is -- and this kind of goes back to some of the questions that I think George from El Paso and Greg maybe from Transwestern mentioned earlier about sort of maybe some question or confusion about the relative selection or flows in the model of Canadian gas vs. Southwest Gas. And what we see is, because the Redwood Path was economically preferred in the model and the Reference Case, that when we constrain Redwood, we then end up shifting those constrained flows from Redwood to Baja. And so you see the impact of the 200 a day constraint on Redwood is to shift that to Baja, essentially. But that's the only real change that you see in the model as a result of constraining capacity by about 500 a day.

Now, the table here that you've got there, except for this column over here on the right, and if I were clever, I would have made this so that I could just hide that until I was ready to talk about it, but I'm not that clever, so ignore this column for the moment because it's not in the table that's in the study, the rest of this is.

What we did in this table is try to illustrate how PG&E would actually meet demand on a cold day. I use this to draw some inferences about what an average day might look like and give some advice, if you will, to core customers and other market participants. The two columns, December 8 Recorded, 2009 Recorded Demand, and on the day after, on the 9th, about 4.1, 4.2 Bcf per day on the PG&E System, and what you see in these rows down here are how PG&E met that demand, and so when these peak days or relative peak days that happened relatively recently occurred just about a couple of years ago, you can see the flows on the PG&E system that allowed it to meet this demand and, in essence, Baja was pretty close to full, Redwood was maybe half full, and then we had some California production added to that. PG&E pulled a lot of gas from storage on that cold December day, and a lot of gas came from independent storage. Same thing really happened the next day, the numbers shifted around a little bit, but it's basically the same story over again.

So then what we did is note that we pulled the winter peak day demand from the 2010 California Gas Report and that PG&E's winter peak day demand was about almost 4.3 Bcf, which is pretty close to the September 9th, 2009, a little bit higher than the day before by about 100-200 a day, but pretty darn close. And then we said, no, let's see what happens when we have our constrained capacity. And we assume that this capacity would be fully utilized, by the way. So we had 1,800 in for Redwood and 733 for Baja, those numbers are a little bit -- the 733 is just a little bit lower than what we had in the model because there was a change in the number that we saw in Pipe Ranger between the time that we started the model until when we did this analysis, so we went with the more conservative number here. And you can see the kinds of numbers, we assumed a fairly large hefty storage pull from PG&E storage for core customers, and then we had to pull about 500 a day more from independent storage in order to satisfy the 42, the 4.3 Bcf per day demand.

Now, interestingly enough, supposing that we were in a scenario in which we had 1,800 available, but customers nominated their gas and they only nominated the number that is more like 800 or 900 like they did back in December 2009, and then you have to pull more gas from storage in order to satisfy all demand. So that's what we wanted to highlight with that particular column.

Now, we can turn that into sort of drawing some inferences about what would happen on an average day, or really any day in between, and we just put the same numbers here in this column that I told you earlier not to look at until now, now you can look at it. So we put the same numbers for capacity in here, 1,800 Redwood, 733 Baja, 130 or so per day from California production, and we assumed a much smaller, more like an average colder winter month storage pull for PG&E storage, and if nothing came from independent storage, the amount of demand that we could serve under those conditions with those kind of deliveries and capacities available is just about 3 Bcf per day. So that you can see here, between 3 Bcf per day and going up to 4.3, basically the entire increment of that has got to be met with gas from storage. So two things that we said in the report, one is that we encouraged non-core customers to make as much use of the existing available backbone capacity for the rest of the injection season as they possibly could, to get as much gas into storage as possible; the second thing, this allows us or leads us to encourage non-core customers, and particularly those who are using independent storage, is to be prepared to use it this December and January if the capacity numbers on the backbone stay where they are. And that's a big "if." As we watch Pipe Ranger, we see it change every day or every couple of weeks, it goes up, it goes down, most recently it's gone up. There have been some days that it went down that were after staff had done its initial analysis, and so what we've learned is that we have to keep an eye on it and continually update our expectations. And as we get closer to winter, of course, PG&E is watching these too, but we're just trying to provide an extra set of eyes and ears on that.

COMMISSIONER PETERMAN: Katie, can I interject with a question?

MS. ELDER: Yeah. Do you want me to stay on that page?

COMMISSIONER PETERMAN: Sure. A little bit of my ignorance about storage. Is there a difference in the PG&E storage and the independent storage besides the capacity?

MS. ELDER: There is. In essence, it works this way. Most of the PG&E storage is what we call "old traditional reservoir storage," where basically -- this is not 100 percent true, but think of it as 90 percent true -- they work to fill it all summer long and then withdraw the gas out of that storage over the course of a single winter, and so it's single cycle storage. The independent storage, though, is much higher pressure, high deliverability storage where they can do several injection withdrawal cycles over the course of the year. One of the things that we saw in 2000 with the power crisis and some other events that occurred late that summer with an explosion on the El Paso System at Las Cruces, was that high prices had led non-core customers to delay their storage refill. And then you had this explosion that took out part of the El Paso System, which impeded their ability to fill storage late in the season. We ended up that winter on November 1st going into the winter storage withdrawal season with not having full storage in Southern California, in particular. And so part of what we wanted to be able to tell non-core customers this time was "pay attention, guys, things could get interesting if it gets cold early," and sort of try to get customers that warning early rather than let them sit and potentially not hear that message, and not take advantage of the opportunity that is there now with some spare, but the little spare backbone capacity there is to make sure that that gets used. So that's the general difference between the two. The customers who tend to use that tend to be not only non-core customers, but marketers, and they tend typically to be playing more of a price optionality game, trying to make money on the margin or on price volatility, rather than using it for reliability. That's not totally true, but it's often the case that that's what they're up to.

COMMISSIONER PETERMAN: And those are the ones storing or independent storage?

MS. ELDER: Correct. Correct, that's what I was talking about.

COMMISSIONER PETERMAN: Thank you. That was very illuminating.

MS. ELDER: We also looked at whether or not we thought we could refill storage, which is a great lead-in to this next page, Commissioner. What we did is we looked first at whether or not we thought we could -- whether it looked like PG&E would be able to get storage refilled for core customers. We constructed a little analysis, you know, where we start the storage inventory at zero at April 1st, it's not always zero on April 1st, but it's usually kind of close. And then we took the injections and withdrawals that were posted on Pipe Ranger and, by feeding those into a spreadsheet analysis, we could calculate the ending month storage inventories. And so that gave us some confidence with what we were seeing actually go into storage. What we were seeing in terms of backbone availability, that storage indeed for core customers would be filled by November 1^{st}.

We then did a second cut at which we looked separately at independent storage. It's harder to look at independent storage because of the multi-cycle capability, you know, PG&E is much easier to look at if you assume one cycle, but when you get into the independents, you've got more than one cycle and their inventory is not posted anywhere, you have to sort of guess a little bit, more -- what's the right word -- a lot more uncertainty about where the inventory is in a given moment. And of course, for competitive reasons, they don't particularly want to share that information. So we went ahead and set it to zero knowing that that could not be reality, but we wanted to see how that would play out, then go ahead and put in the injections and withdrawals that we could see posted from Pipe Ranger. It looked to us like most of the independent storage could be full by November 1^{st}, but probably not all of it. And, again, that just amplified our overall conclusion that we wanted to tell non-core customers to pay attention, use every opportunity they've got to fill storage now, so that the gas will be there in January if we need it in January.

And that's all I've got. Can I answer any other questions? Bob should get to ask first.

MR. COWDEN: Can I make a comment or a question?

MS. ELDER: I think you're allowed either, or both.

MR. COWDEN: I guess first a comment, I think Katie is spot on with the main message that comes out of this in terms of the gentle reminder of customers, fill storage, think seriously about using storage this winter because it's one of the key things in the toolkit to help get customers through the winter, kind of that in addition to a lot of enhancements to our C&G and LNG peak shaving programs that we have. Those will be things that really help get us through the winter.

I did have a comment on some of the storage numbers, that I think Katie's expected deliverability for an average day is not an unreasonable number, the 3 Bcf for the total demand. I'm not sure how you derived that, but that's similar to what we have expected in January and February. And like you mentioned, the Redwood capacity is now posted at 2050. The one thing with the storage numbers on the PG&E system is that's an average day deliverability of the 350, but our capability to deliver storage on an average day, or even at the end of the winter, is more like 750 to 800 MMcf a day. So just be a little careful about mixing actual usage and capacities because our actual withdrawal capacities are higher than those numbers. And on a peak day, you know, looking over the last three years in the winter, you know, we've been able to withdraw more than the 1,100.

MS. ELDER: Right, but you've also done that because you're relatively conservative on withdrawals earlier in the winter and maintain field pressure after that APD date so that you had the ability to do that. So you can't do that for more than, say --

MR. COWDEN: You can't do it for every day through the winter.

MS. ELDER: Precisely.

MR. COWDEN: Fair enough.

MS. ELDER: But you can peak up to it when you need to.

MR. COWDEN: You can peak up to it when needed and the likelihood of having a peak day every day in a winter is infinitesimal.

MS. ELDER: We hope that that is infinitesimal, yes.

MR. COWDEN: So, just kind of to wrap up, good numbers, but keep in mind deliverability actual vs. capability.

MS. ELDER: Right and that's why we made sure that we showed December 8th and December 9th from 2009 and showed these much higher numbers, but recognize that you never plan to do that through the whole winter.

MR. COWDEN: Right.

MS. ELDER: Greg Klatt had his hand up.

MR. KLATT: Thank you, Katie. I wasn't sure I understood how you derived the 733 number for Baja.

MS. ELDER: The 733 number was posted on Pipe Ranger on a given day. I couldn't tell you off the top of my head now what day it was that it was down that low.

MR. KLATT: And then you used that for expected deliverability? I mean, I guess you're saying -- you understand the capacity is much higher than that, but you're saying that is how much you expect they could flow on an average basis?

MS. ELDER: Right. PG&E has been posting on its Pipe Ranger website the actual deliverability for individual days and what they expect to be available through December 31st given all the stuff that's going on on the system.

MR. KLATT: Okay.

MS. ELDER: There have actually been days where it's been lower than 733. But at one point, there was a note that said we think that, from now through the rest of the year, it will be 733.

MR. KLATT: All right. So, but it’s a product of all the other things that are going on on the system?

MS. ELDER: Right, on the hydrostatic testing, the class location study, the individual lines that the CPUC has actually ordered for PG&E to operate at reduced pressure, all of those things together have led to them posting specific numbers on Pipe Ranger, but they update periodically.

MR. KLATT: Thank you.

COMMISSIONER PETERMAN: Katie, I had just a presentation question. Should the colors mean anything to me?

MS. ELDER: No, the colors were there just to highlight for you, just to draw your attention to the difference between what happened in 2009 that was recorded data vs. the assumptions that we made based on the data that we saw on Pipe Ranger in this particular column, and over in the green column, I guess we were saying an average day is green.

COMMISSIONER PETERMAN: Thank you for explaining that.

MS. ELDER: Can I answer anything else? Cool. So we’re back to Ruben and Ivin, then.

MR. TAVARES: Okay, thank you Katie. Okay, now we have Ivin Rhyne, he is our Office Manager and he’s going to address the summary and also some potential work that we may do over the next couple months.

MR. RHYNE: All right, so I have the enviable position of talking to a room full of people who have been staring at graphs, charts, numbers, and have been talked to about potential future maybe uncertainties about natural gas, and wrapping this up for the day. I do want to emphasize a couple things. First of all, a very important date, October 11th, 2011, that is the day that we're asking for submission of comments. I would really encourage those of you who intend to submit comments to please do so early and voluminously, hopefully, and thoughtfully.

Really this whole process is not about what we just think in a cocoon or a shell, it's about what we think and how that interacts with what our stakeholders think, and how we can improve things going forward. Over the next couple of months, we're going to take that feedback, a lot of the feedback, really excellent feedback and I want to thank all of our panelists who are here, and some who had to take off early, for participating, also for the audience members who participated. I want to also really just extend a thank you from the staff to the Commissioners, who have been very supportive of this whole process as we go through this, they’ve been very engaged with this, as well.

Now, over the next few weeks, as you contemplated your comments, I’d like to leave you with just three main questions, the first one being, and this one is pretty straightforward, what issues or problems do you see with the scenarios as they’re currently constructed in the Reference Case? There have been a few questions raised, and as you take this, as you digest it, that kind of feedback is going to be very important for making sure that we improve the quality of the analysis that we’ve done to date.

The second question, what other or different scenarios do you think would be of value for us to run and why? So, we’re not going to promise that we have unlimited resources, or unlimited time, but certainly that information and feedback with regard to what additional analyses could be done would also be very valuable.

And finally, the third question, and in this I want to be very careful not to limit your thinking with regard to the forecasts or the values that we put forward here, but what gas-related policy recommendations would you propose and why? Certainly, there is a lot of decisions that could be made with regard to natural gas going out in the future, this is a natural time, a natural point for us to be looking out into the future, so those policy questions, what are some policy relevant recommendations that you would make, and why?

I would also like to emphasize once again that staff does not have a crystal ball, we don't look out into the future and tell the future, if we did, we would be in the lottery business, not the natural gas business, or, I don't know, it depends. The point being that we have some tools that are extremely powerful and extremely useful, and we attempt to make good use of those tools with regard to the questions at hand, but we're always looking to do better, we're always looking to do more, we're always looking for ways that we can improve what we do with regard to the feedback, what is valuable to you as a stakeholder is certainly of interest to us as the State staff with regard to natural gas. And so, with that, I'm going to stop pestering you with my comments. I'll turn it over to the Chairman and Commissioner Peterman, if you have any closing thoughts before we wrap up for the day.

COMMISSIONER PETERMAN: Thanks, Ivin. First, I'd just like to make sure we open it up to any public comments. Is there anyone in the room who has been wanting to say something, but hasn't found the right time, or on the phone lines? Great, glad that you're all satisfied with the forecasts as they are, just kidding. Chair.

CHAIRMAN WEISENMILLER: I would certainly like to thank the staff for their hard work on this and certainly thank the participants in the workshop today for giving us good feedback on this report. We're certainly looking forward to moving forward; obviously, these are complicated issues, but I think in terms of trying to get an understanding of what some of the policy connections are, what the uncertainty is and how that plays back and forth with our policy decisions, is always helpful.

COMMISSIONER PETERMAN: I agree and I want to thank staff for their hard work on this report. In particular, what I was looking for with this report was to see some of the policies that we've just implemented, or that we're talking about now, such as the 33 percent RPS, the 40 percent RPS, a DG goal, reflected in one of the scenarios. And indeed, you can look at the High Price, the Low Price cases, High Demand, Low Demand cases in California, and see how that could include some of the scenarios we've talked about. And I look forward to the next iteration and continued involvement by all the stakeholders. Thank you so much for being here, particularly to our panelists, Ms. Vu, and Mr. Wilder. Thank you. We are adjourned.

((Adjourned at 3:35 p.m.)