COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Informational Proceedings and	)
Preparation of the 2003	) Docket No.
Integrated Energy Policy Report	) 02-IEP-01
_____	)

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

WEDNESDAY, FEBRUARY 26, 2003

10:00 A.M.

Reported by:
Valorie Phillips
Contract No. 150-01-005

COMMISSIONERS PRESENT

James Boyd, Presiding Member

William J. Keese, Associate Member

ADVISORS

Scott Tomashefsky, Advisor

Susan Bakker, Advisor

Melissa Jones, Advisor

STAFF PRESENT

Al Alvarado

Karen Griffin

David Abelson

Bill Wood

David Vidaver

Magdy Badr

Judy Grau

Mark DiGiovanna

ALSO PRESENT

Steven Kelly, Policy Director
Independent Energy Producers Association

Tom Miller
Pacific Gas and Electric Company

Mark R. Minick, Manager of Generation Planning
Southern California Edison Company

Mark J. Skowronski
Duke Solar

Jeff C. Huang, Market Forecast Consultant
The Gas Company, Sempra Energy

ALSO PRESENT

David L. Arthur, Energy Supply & Marketing
Redding Electric Utility

Gary DeShazo, Regional Planning Manager
California Independent System Operator

Mark A. Meldgin, Senior Business Planner
Pacific Gas and Electric Company

Brian C. Prusnek, Regulatory Analyst
California Public Utilities Commission

Don Smith, Regulatory Analyst
Office of Ratepayer Advocates
California Public Utilities Commission

Morteza Sabet, Manager
Western Area Power Administration

Chifong Thomas, Principal Consulting Engineer
Pacific Gas and Electric Company

Robert Sparks
California Independent System Operator

Michael S. Alexander, Manager
Southern California Edison Company

Stephen Hall

Kent F. Hampton, Marketing Manager
Marathon Oil Company

William Marcus
JBS Energy

Joe Alves
BP Energy Company

Richard McCann
M-Cubed

Curt Hatton, Manager
Pacific Gas and Electric Company

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

2 10:00 a.m.

3 PRESIDING MEMBER BOYD: Welcome to day

4 number two of Commission Committee's workshop on

5 the integrated energy policy report and the

6 electricity and natural gas report specifically.

7 No introductory remarks today; we did all those

8 yesterday, so I'm just going to, with Mr. Keese's

9 permission here, Commissioner Keese, we'll

10 dispense with any speeches and turn it right over

11 to you, Al, to get into today's topic areas.

12 MR. ALVARADO: Okay. Good morning,

13 everyone. This is the second day of the

14 Integrated Energy Policy Report workshop. For

15 those of you that weren't here yesterday my name's

16 Al Alvarado. I am the Project Manager of the

17 Electricity and Natural Gas Report, which is one

18 of the three reports that are being prepared in

19 support of the Integrated Energy Policy Report.

20 Yesterday we covered three staff draft

21 reports; one was the demand forecast, and the

22 other two were on our retail price forecasts, our

23 preliminary forecasts.

24 Today we're going to cover two other

25 reports. The first one will be on our preliminary

electricity and natural gas infrastructure assumptions. And the second report will be on our preliminary cost of central station generation technologies.

As I said yesterday, we are recording this workshop, and the intent is really to track your comments. But it will require you to come up to the microphone and speak into the microphone so we can capture all your comments for our later review and making sure we're not missing anything.

When you do come up to the microphone can you also please pass on your business card to our court recorder to make sure that she'll be able to spell your name correctly. And despite this formality I do hope that we can foster a little more lively and open discussion since the purpose here really is to get comments from you.

With that being said, I'm going to pass on the mike to Mark over here who is going to initiate our discussion on the first report.

MR. DiGIOVANNA: All right, thanks, Al. My name is Mark DiGiovanna. I am the staff's lead for the preliminary electricity and natural gas infrastructure assumption staff draft report. And we did want to make that title longer, but they

1 wouldn't let us, so --

2 (Laughter.)

3 MR. DiGIOVANNA: This report is intended

4 to answer the question of what changes in

5 electricity and natural gas infrastructure are

6 likely to occur in the next ten years.

7 To do this we've broken this into three

8 sections: electricity generation; electricity

9 transmission infrastructure; and natural gas

10 infrastructure.

11 In a moment David Vidaver will come up

12 here and talk about the assumptions that we are

13 making in what electricity generation

14 infrastructure additions will be made in the next

15 ten years.

16 He'll be followed by Judy Grau, who will

17 talk about electricity transmission infrastructure

18 additions.

19 And then finally I'll come up here and

20 talk about the natural gas infrastructure

21 additions that have come online since the energy

22 crisis, as well as the several projects that we

23 see coming online in the next few years.

24 Hopefully by the end of this what we'll

25 have is a good set of assumptions on the resource

1 additions that will be made over the next ten
2 years. We will use this in all of our upcoming
3 reports, which will be another electricity report
4 which will be coming out in March; the 2003
5 natural gas market outlook report which will come
6 out in April; the electricity and natural gas
7 report which is obviously the policy report --
8 IEPR; and then the final IEPR.
9 So we would appreciate and hope that
10 you'd give us as many comments as possible, as far
11 as if these are reasonable assumptions, if you
12 have knowledge otherwise. And from there we will
13 be able to get all these other reports done.
14 One other note. I just want to
15 reiterate what Al said, Valorie asked me to remind
16 everybody to be sure to give her your business
17 card if you want to make sure your name is spelled
18 right in the transcript. And also to speak into
19 the microphone. And if you're a repeat offender,
20 if you spoke yesterday, you don't need to give her
21 your business card, so you're all right there.
22 So, with that, I will turn it over to
23 Dave.
24 MR. VIDAVER: Thanks, Mark. I usually
25 start off by telling a joke to put myself at ease,

1 because I don't like doing this. The only
2 thing --
3 PRESIDING MEMBER BOYD: I noted the tie,
4 David, I mean that was --
5 (Laughter.)
6 MR. VIDAVER: The only joke I could come
7 up with this morning was really inappropriate.
8 (Laughter.)
9 MR. VIDAVER: And I'm sure it would
10 really offend Karen, who would never let me near a
11 microphone again. So, two FERC Commissioners walk
12 into a bar -- it is too inappropriate to tell --
13 (Laughter.)
14 MR. VIDAVER: Gee, they taught me how to
15 use this just a moment ago. Click on my name --
16 PRESIDING MEMBER BOYD: For the
17 audience's benefit yesterday we tried to imply
18 this is supposed to be a very informal workshop.
19 We're stuck with the way this room is set up, but,
20 you know, it should just be a nice, big giant
21 roundtable. But we should have had David as the
22 opening act yesterday morning, too.
23 (Laughter.)
24 PRESIDING MEMBER BOYD: To put the
25 audience at ease a little more, so anyway, you're

1 doing good, David.

2 MR. VIDAVER: Thank you, Commissioner.

3 Chapter one, generation infrastructure. A little

4 overview of what we're going to talk about. An

5 outline. We're going to briefly discuss changes

6 in resource adequacy for 2000 to 2003, very

7 quickly.

8 Assess current market conditions,

9 perhaps not as quickly, but we all know what they

10 are. Natural gas is trading at about $19 right

11 now. So that's the bad news. The good news is

12 that SoCal border prices are trading at about a 40

13 percent discount.

14 Then we're going to go over likely

15 changes in infrastructure from 2004 to 2006. We

16 have some idea, we'll admit we're sort of

17 guessing. And solicit your input as to what you

18 think is going to happen.

19 And then 2007 - 2013, I wanted to type

20 about 15 question marks there. Go over some of

21 the uncertainties, all of which I'm sure you're

22 familiar with.

23 Then roll out our baseline projections

24 for your critique, and some of the scenarios and

25 sensitivities that we're going to run. The

1 baseline is just designed as sort of a plausible
2 set of additions, off which we can analyze
3 sensitivities. The conclusions we come to, to the
4 underlying assumptions that we make.
5 So, that being said, can't discuss
6 resource adequacy without nodding toward demand.
7 As Lynn Marshall discussed yesterday, peak demand
8 has fallen since 2000 these are the weather-
9 adjusted ISO peak loads. The horizontal black
10 line are the normalized monthly peaks, so you can
11 see we've done a pretty good job of conserving. I
12 believe those numbers are adjusted for things
13 moving in and out of the ISO; the City of Pasadena
14 and SMUD.
15 New generation. These are the plants
16 200 megawatts and larger that have come online
17 since 2000. They've actually come online since
18 2001. None of these came online in 2000. So you
19 can see we've built quite a bit of capacity.
20 Some of that is actually dedicated to
21 California loads. I believe Sunrise is; a couple
22 others are, too, but -- never mind.
23 The procurement review --
24 MS. JONES: David, what's in the other
25 category?

1 MR. VIDAVER: What's in the other
2 category? The 1873 megawatts of plants less than
3 200 megawatts.
4 MS. JONES: Okay, thank you.
5 MR. VIDAVER: Okay? Sorry. Everything
6 over 200 is broken out. If I begin to like shiver
7 violently and my head jerks back, it's because I
8 have access to information related to interim
9 procurement.
10 And if I accidentally reveal anything
11 that I'm not supposed to, Karen is going to jolt
12 me here. So if I just go whoops in the middle of
13 a sentence where I'm talking about a particular
14 power plant or a particular contract, I hope
15 you'll understand.
16 We've also got a number of plants which
17 are going to come online between now and the end
18 of this summer. And while in the past some of the
19 projections about capacity due to come online have
20 been optimistic, as it were, these are pretty much
21 done deals.
22 Four of those should be online within
23 the next three months. Elk Hills, for example, is
24 a Sempra plant, and Sempra has obligations under a
25 DWR contract that it cannot currently meet out of

its own capacity, so Elk Hills is done.

High Desert is in a similar position. That's a constellation contract with DWR or through DWR. Sunrise is another one of those plants I don't think I could say exactly when it will come online, because Karen will jolt me. But it's part of a DWR contract, as well.

And I believe La Paloma 2 and 4 are actually testing as we speak, so. That's another 3300 megawatts of capacity that we should have online by the end of the summer. If you add those up you get about 9300 megawatts of new capacity.

And the trend growth rate in load in California is such that we need about 1200 megawatts of capacity each year. So we've basically added something like seven years worth of capacity, in a loose sense, since 2000.

The Northwest. Loads have dropped dramatically in the northwest for a number of reasons. Most notably the utter collapse of the aluminum industry which constitutes about 6 percent of northwest loads. I think eight of the ten smelters in the northwest have shut down.

There is very little indication that any of that load will return. Aluminum prices are

very low; these smelters tend to use an obsolescent World War II era technology. The preferential entitlements that they receive from BPA are probably going to be slashed in 2006 from I believe it's 2800 megawatts down to 600.

The remaining aluminum industry in the U.S. is moving to the Ohio Valley. And China will probably become the world's largest producer of aluminum by the end of the decade.

These loads are not weather adjusted, so you can't just look at them and say, well, in 2002 whatever conservation appeared in the northwest the prior year had disappeared. Unfortunately I can't provide you a weather-adjusted set of data. The Northwest Power Pool provides that for energy, but not for peak loads. There is some recovery in the northwest, but it's not substantial.

Not only has there been new capacity in California, there's been a lot of it throughout the remainder of the WECC. The triangles represent plants which are now online larger than 200 megawatts, have come online since 2000.

Again, we expect quite a bit of capacity to come online elsewhere in the WECC by the end of the summer. The Calgary Energy Center began

1 testing on Monday, for example.
2 The Mesquite plant is another -- yes,
3 ma'am?
4 UNIDENTIFIED SPEAKER: I'm confused.
5 This one includes California, too?
6 MR. VIDAVER: Well, --
7 UNIDENTIFIED SPEAKER: This 6649?
8 MR. VIDAVER: No; the 6649 is the total
9 amount of capacity outside of California that is
10 not online but expected to be online by the end of
11 this summer. Sorry.
12 The Mesquite plant is another Sempra
13 owned plant which will, in all likelihood, be
14 dedicated to serving California loads. The TDM
15 plant, Thermodynamica Mexicali, is another Sempra
16 plant, which barring transmission constraints,
17 will be used to satisfy load in California.
18 The Goldendale plant is highlighted;
19 it's the one located at the Oregon/Washington
20 border. It is probably not going to make the
21 summer deadline, almost certainly.
22 This information changes daily. We
23 scour the web and the trade press on a daily basis
24 and things move in and out. But for every plant
25 that gets canceled, delayed, for example, like

1 Goldendale, we just heard yesterday that SUMAS 2,
2 a 600 megawatt facility at the Washington/Canada
3 border is almost certainly going to go forward. I
4 think they were actually approved, and then
5 because of delays they had to refile. And they've
6 done that.
7 So for everything on here that might
8 slip there's something else that might actually
9 appear, not by the end of the summer of 2003, but
10 certainly within the next two years.
11 So, the bottomline is we've seen a
12 substantial increase in reserve margins, both in
13 California, the northwest and the southwest.
14 Again, you're talking about six and seven years
15 worth of load growth being met by this capacity.
16 So the conclusion is that resources are
17 adequate to insure reliable, competitively priced
18 electricity through 2005. Now, there are some
19 caveats.
20 Competitively priced electricity doesn't
21 mean cheap electricity. And here we're talking
22 about the wholesale spot market. Today the ISO --
23 energy market is trading well over $100 --
24 slightly over $100. But with gas prices at the
25 border being in the $11 and $12 range, that's

1 perfectly understandable.

2 There is really no amount of generation

3 capacity that can guarantee low gas prices. And

4 as our gas office will probably talk about this

5 afternoon, gas prices probably won't remain low.

6 They'll probably stay high for a couple of years.

7 But I'm not the one to talk about that.

8 MS. JONES: David, you talked a little

9 bit about the northwest loads. Can you just

10 briefly talk about what's going on with loads in

11 the southwest?

12 MR. VIDAVER: The southwest load data is

13 really hard to get a handle on. They don't have

14 such agencies as the Northwest Power Pool and the

15 Northwest Power Planning Council. So,

16 compilations of their recent loads are really

17 tough to get ahold of.

18 It's my understanding that loads in

19 parts of the southwest, specifically southern

20 Nevada, are actually not slowing down. But the

21 loads in Arizona are declining somewhat. That

22 would no doubt be a result of the macroeconomic

23 situation.

24 Those arguably will remain the fastest

25 growing areas of the country. And the extent to

1 which loads continue to grow there will probably
2 be -- they'll probably only be dampened by price
3 increases, which they've experienced. And blamed
4 on us, by the way, so.
5 CHAIRMAN KEESE: Let me ask, are
6 capacity withdrawals included in this? Or is that
7 another -- are we going to hear about that later?
8 MR. VIDAVER: We haven't -- there's
9 nothing in this presentation which indicates how
10 much capacity has come offline in the past two
11 years. It's a very very small amount.
12 However, as of December 2002, some
13 capacity was constrained by the South Coast Air
14 District, which required that some plants shut
15 down because of failure to install emissions
16 retrofits. Ron Weatherall is not in the audience,
17 but --
18 CHAIRMAN KEESE: I thought I recalled
19 1300 megawatts.
20 MR. VIDAVER: Yeah, I was going to say
21 it's about 1200 megawatts. But actually some of
22 that has -- a share of that has received approval
23 from the Air District to install after-the-fact
24 emissions retrofits and actually come back online.
25 So the actual number is probably going to turn out

1 to be slightly below 1000.
2 So, recent spot market conditions.
3 We've gone through the last six or seven months of
4 2002 because of gas prices that are low by recent
5 standards. We've experienced very very low spot
6 market price.
7 I've provided two series here. The red
8 series is the ISO imbalanced market price. These
9 are sort of unweighted monthly averages. The
10 imbalance market price is an average of the ISO's
11 (inaudible) prices. May or may not have much
12 meaning. So we also provided the economic inside
13 survey price. They're a group in Oregon which is
14 part of the industry, trade press.
15 So we're seeing prices crawl back up.
16 In fact, in the last six weeks they've crawled
17 back up at about 65 miles an hour. We have very
18 high prices right now, but what you have to keep
19 in mind is that the high prices are not a result
20 of a lack of generation capacity.
21 There was an article in a recent, I
22 think last week's Power Markets Weekly that
23 implied that we're back to 2000 in large part
24 because of the hydro conditions in the northwest.
25 And I would strongly disagree with that. Bill

1 Wood in our gas unit can provide you far more
2 accurate information about the run-up in gas
3 prices than I can. But I can assure you it
4 doesn't -- I would like to assure you that it has
5 nothing to do with capacity shortages.
6 Even if spot market prices stay at the
7 level they're at now, we've dramatically reduced
8 our exposure to the spot market. I've provided
9 some numbers here related to the three investor-
10 owned utilities.
11 What has basically happened is that the
12 DWR contracts, combined with the interim
13 procurement proceeding, have dramatically lowered
14 the exposure of the investor-owned utilities and
15 its customers to the spot market.
16 I guess taking this in order, the
17 utilities have their own thermal assets consisting
18 of hydro and nuclear units primarily. They also
19 have QF contracts. They have must-take DWR
20 contracts. About 90 percent of the energy under
21 those contracts is at fixed prices; very little of
22 it is exposed to gas price risk. And that which
23 is can be hedged. I understand the utilities can
24 hedge gas prices right now. They have other long-
25 term contracts with WAPA and BPA, out-of-state

1 entities.

2 And then the DWR dispatchable contracts,

3 most of which are indexed, I think all of which

4 are indexed to the gas price, leave the utilities

5 with some gas-price exposure. But, they can hedge

6 that, unlike four years ago.

7 So the total capacity available to them

8 onpeak is about 4000 shy of what they're going to

9 need. So this is saying that they have to go out

10 in the spot market for 4000 megawatts during the

11 hottest hour of the year.

12 Well, two things should be noted. None

13 of the interim procurement numbers are in here.

14 If we told you what those were we'd have to kill

15 you. So, assuming that half of that has been

16 taken care of, you can say that onpeak the

17 utilities are going to have to go out into the

18 spot market for 2000 megawatts.

19 Well, they always have the possibility

20 of signing balance -- quarter contracts; and can

21 effectively reduce their spot market exposure to

22 nothing if the PUC so allows it.

23 The other thing to remember is that the

24 peak hour of the year is indeed that, it's peak

25 hour. And you only get to within a couple

1 thousand megawatts of that maybe five or ten hours
2 of the year.
3 Even during the rest of the summer
4 you're usually, 2-, 4-, 5-, 10,000 megawatts, 5000
5 megawatts shy of your peak. So what this is
6 saying is that the exposure of the investor-owned
7 utilities in the spot market during the summers of
8 2003 and 2004 is negligible.
9 So while we may not like the fact that
10 we're faced with the possibility, given current
11 gas prices, of paying $100, $150, maybe even more,
12 in the spot market for electricity this summer,
13 the financial risk associated with that is minimal
14 for the investor-owned utilities.
15 MS. BAKKER: David.
16 MR. VIDAVER: Yes, ma'am.
17 MS. BAKKER: I notice that says
18 coincident peak demand, and I didn't think we did
19 coincident peak demand forecasts. Are you just
20 adding them and assuming the worst case?
21 MR. VIDAVER: No. The demand office has
22 actually calculated the relationship between
23 coincident and non coincident peaks for the state.
24 And they've come up with a factor of about .976.
25 So if you take the non coincident, some of the non

1 coincident peaks and you multiply that number by
2 .976 you get a very good estimate of the
3 coincident peak.
4 MS. BAKKER: Okay, and then this is just
5 the IOUs?
6 MR. VIDAVER: This is just the IOUs, and
7 it's net of direct access. And, of course, we're
8 making an assumption about what share of the IOU
9 load is going to stay out with direct access
10 contracts.
11 And I believe the assumption we made was
12 something on the order of 12 or 14 percent.
13 Yes, Mr. Kelly.
14 MR. KELLY: Dave, just for
15 clarification, so I understand. This is IOU only?
16 MR. VIDAVER: Yes, sir.
17 MR. KELLY: And when I think of IOU
18 peaks in the summer I think of about 45,000
19 megawatts. What you're showing is that -- are you
20 showing that here?
21 MR. VIDAVER: Well, I'm trying to. If
22 you're thinking of 45,000 you're a little high.
23 MR. KELLY: Okay.
24 MR. VIDAVER: Sorry, I mean your
25 number's a little high.

1 (Laughter.)

2 MR. KELLY: I like the way you did it

3 the first time.

4 MR. VIDAVER: We've also reduced, if you

5 take 38- or 39- or 40,000, whatever number you're

6 thinking of, and you reduce that by about 12 or 14

7 percent, which is what direct access is taking

8 away from them, you're getting down to these --

9 MR. KELLY: Okay. So in a hot summer

10 day the IOUs collectively will be -- their

11 residual net short -- the short-term market will

12 be roughly 10,000 megawatts that they'll have to

13 procure? If you're at 42, roughly?

14 MR. VIDAVER: Well, if you were sitting

15 up at 40 --

16 MR. KELLY: Eight --

17 MR. VIDAVER: Yeah, if you were to add

18 6000 to the 34, you'd be looking at 10 for the --

19 MR. KELLY: Thank you.

20 MR. VIDAVER: Okay. A lot has been made

21 of a number of cancellations of new projects. For

22 the past 18 months or so, we've read in the

23 newspaper about how every single megawatt of

24 capacity that anyone has even thought of is no

25 longer in the development stage.

1 So we thought we'd take a look at some
2 of these numbers very quickly. These are
3 applications at the Commission which have been
4 withdrawn since July 2001. July 2001 was when
5 prices all of a sudden returned to something
6 resembling normalcy.
7 These are, again, only plants larger
8 than 200 megawatts. So, that's quite a bit of
9 capacity that's been withdrawn, as everybody is so
10 fond of pointing out.
11 We then have a number of plants which
12 have actually been permitted, some of which have
13 begun construction, that they haven't -- they're
14 not going to meet the online dates that we set
15 perhaps a year ago.
16 For example, I don't know exactly what
17 we assumed that the online date for Pastoria would
18 be when we permitted it, but it's certainly not
19 going to make that date. I believe that only 250
20 megawatts at Pastoria is actually in an advanced
21 state of construction. I'm not sure. Someone
22 from the siting office will no doubt correct me.
23 Contra Costa has stopped construction.
24 Otay Mesa and Metcalf are in red because they have
25 the unique characteristic that the state actually

1 has a right to step in and finish building them if
2 Calpine does not meet construction milestones. So
3 I'd like to highlight them. They're also
4 important for another reason which we'll get to
5 shortly.
6 Mountainview has been postponed,
7 Russell City, et cetera, et cetera. So, these are
8 all plants which have been permitted. Some of
9 which, indicated by the C's on the map, are
10 actually under construction.
11 One thing to note about this is that in
12 the event that it were profitable to do so, these
13 plants could probably come online a lot faster
14 than a plant which is yet to submit application,
15 or have an application approved.
16 And here are some of the plants that are
17 in review at the Commission. Again, it's an
18 almost complete list of plants over 200 megawatts.
19 There are a couple of plants which are missing.
20 The Magnolia plant that Burbank and SCAPA would
21 like to build. The Walnut plant which is, I
22 believe, the Turlock Irrigation District plant; I
23 didn't put on this list, and I'll explain why
24 shortly.
25 But everything else here, East Altamonte

1 1100 megawatts, I believe, is the third plant that
2 the state has step-in rights on. Blythe II is
3 highlighted because I got into kind of an argument
4 with the siting division. Blythe II walked in
5 kind of recently, so they -- it's unfair to say
6 that they are being delayed. They haven't shown
7 any indication of not wanting to come online
8 quickly.
9 But I put them in here because I wanted
10 to give you an idea of despite all the
11 cancellations, despite the low forward prices in
12 the market, this is how many people are still
13 interested, to some extent, in building power
14 plants. Whether or not they actually want to get
15 them online the day after tomorrow -- well, they
16 probably want to get them online the day after
17 tomorrow with prices at $100, but that's a more
18 recent phenomenon.
19 What we have here is despite all the
20 cancellations that we've heard about and people
21 toss around numbers like 50,000 megawatts WECC-
22 wide that are no longer on the drawing board, we
23 still have built enough, put enough steel in the
24 ground to meet load for quite some time. By our
25 estimates, the year 2005.

1 And it should also be remembered that
2 while many of these delays are being attributed to
3 the financial conditions of the developers, we
4 hear numbers of like anywhere between $40- and $90
5 billion worth of short-term debt, that these
6 developers will, in all likelihood, not be able to
7 service over the next 12 to 18 months, that these
8 permits and these partially constructed plants are
9 not going anywhere.
10 They're actually changing hands.
11 Pacific Gas and Electric's National Energy Group
12 actually completed La Paloma, which is over 1000
13 megawatts, but it will never see one megawatt of
14 output. It got the financing to complete that
15 with the agreement that when it was done it would
16 simply turn the facility over to the bank.
17 So, even if all of these facilities are
18 turned over to creditors, it's very likely that
19 the creditors will turn around reasonably quickly
20 and turn them back over to other developers at
21 somewhere, depending on who you believe, between
22 20 and 50 cents on the dollar. Banks do not like
23 to hold these assets. They will turn them over
24 whenever they think the person to whom they're
25 turning them over can cover the debt that they

1 incur.

2 PRESIDING MEMBER BOYD: David.

3 MR. VIDAVER: Yes, sir.

4 PRESIDING MEMBER BOYD: I'm a little bit

5 worried about what the title of this slide,

6 expected delays, conveys to the lay public vis-a-

7 vis those of us who sit around knowing the exact

8 status of various things.

9 I mean, as a Commissioner who sits on

10 some siting cases, I mean some of those are going

11 slower, let's say, in the permitting process than

12 one would have hoped, but that's due to not

13 necessarily financial conditions or any desire to

14 build, it's just a tough project to permit, and

15 they're going slow.

16 So, some of these are going slow, but I

17 don't see the fact that -- I don't see that

18 they're not going to be built and be online vis-a-

19 vis some that the intricate financing web you wove

20 there may be caught up in that.

21 So I think I just want to caution the

22 audience that -- and the media, in particular,

23 that you really got to get down case-to-case. And

24 I don't want to convey that, oh, boy, we're

25 expecting delays in all these projects. Because

1 some of them are just going slow permitting-wise,
2 but we don't, in a few cases I know specifically
3 we don't see any reason why they won't be built
4 and operated.
5 MR. VIDAVER: I could have chosen the
6 title far more carefully. We normally expect the
7 siting process to take a certain length of time.
8 And following that we have an 18- to 24-month
9 construction period. And given the location of
10 these projects in queues, we would expect an
11 online date at some point in the future.
12 The fact that these plants will probably
13 not come online, with the exception of Blythe II,
14 at that time is not a function of problems
15 encountered in the siting process. And in these
16 cases it's not necessarily a result of financing
17 problems.
18 The simple fact is that until a couple
19 days ago, forward prices were so low that it
20 didn't make sense to bring a power plant online.
21 You could not cover debt service.
22 So, these delays are primarily a result
23 of the fact that you want a placeholder in the
24 queue to build a power plant, assuming that at
25 some point in the not-too-distant future it will

1 be profitable to operate.
2 But I received permission from the head
3 of our siting office to say that many of these
4 plants are in no hurry. Now, the events of the
5 last couple days may change that, but in any case,
6 until recently forward prices have been such that
7 whatever incentives there are to apply for a
8 permit, there have not been substantial incentives
9 to get that plant online really quickly. So I
10 hope that clarifies what is meant by this slide.
11 All righty, now we get down to the fun
12 stuff. Looking forward, we're in an environment
13 where we can't look forward with any degree of
14 certainty. We don't have -- we don't model single
15 utility areas, we don't use screening curves, we
16 don't know what exports or imports are going to be
17 available, and we don't know what gas prices are
18 going to be. And we don't necessarily sit down
19 with load serving entities and come to some kind
20 of consensus of these matters.
21 So, what we have tried to do in
22 establishing a baseline resource assessment is
23 come up with a plausible future. What this future
24 entails is a bit of guesswork and some basic
25 assumptions about what the future will look like.

1 With respect to some of these plants
2 that we are going to assume are built and come
3 online during the next three years, we have what
4 we think is very very solid information. And I'll
5 go over these individually to give you an idea as
6 to how confident we are, in some cases, and how
7 much conjecture is involved in others.
8 We see in California from the end of the
9 summer of 2003 until the beginning of the summer
10 of 2006, 4200 megawatts of capacity coming online.
11 Los Angeles Department of Water and
12 Power is repowering two major units which would
13 otherwise have to shut down for failure to install
14 appropriate emissions controls. These are their
15 Valley facilities and the Haynes facilities.
16 Haynes is in red, as are a couple of other bits of
17 information. This indicates that the numbers or
18 the dates or the names have changed since the
19 February 13th document that we issued.
20 So, as I said, this is a very dynamic
21 environment; we're constantly trying to keep up
22 with the set of rapidly changing facts. And
23 accordingly, the numbers of two weeks ago aren't
24 necessarily the numbers today. So, for example,
25 we didn't assume that Haynes was going to be

1 repowered until about ten days ago.
2 So, LADWP is repowering about 1100
3 megawatts of capacity. There will be another
4 slide which shows how much capacity we think is
5 being retired. The difference between the Haynes
6 repower and the amount of capacity being retired
7 by LADWP is guess about 49 megawatts.
8 Salton Sea 6 has a 20-year contract with
9 the Imperial Irrigation District to sell 100
10 percent of its output. It's going to be built.
11 Several of the remaining plants, Vernon,
12 Walnut, Magnolia are owned by municipal utilities
13 that are either replacing them with new facilities
14 or find themselves onpeak caught short in the
15 market, and are arguably attempting to reduce
16 their exposure to the spot market; or they have
17 long-term contracts expiring. And so we're very
18 confident that these plants will be built,
19 especially if spot market prices stay at $100 for
20 any length of time.
21 Kings River peaker and the San Francisco
22 Airport peakers are the turbines that were secured
23 from Williams. They're in contract renegotiation.
24 We say San Francisco Airport, because it's
25 probably the one place in the City that nobody

1 cares if they have a power plant next to them. So
2 we're just being a little sensitive to their
3 needs. There is no San Francisco Airport site.
4 Pico is another one of those muni-owned
5 plants; it's being built by Silicon Valley Energy,
6 or the City of Santa Clara. Cosumnes is being
7 built by, or would like to be built by SMUD. And,
8 again, this is a municipal utility short on peak.
9 And we figure they're very very serious about
10 building this. Municipal utilities have captive
11 load, as it were, and they have basically have a
12 pretty much a guaranteed revenue stream which will
13 allow these plants to prove profitable. MID Cogen
14 is another plant being built by a load serving
15 entity.
16 The two shaky ones on here, as it were,
17 are Metcalf Energy and Otay Mesa. We happen to
18 think that Otay is going to go forward, in large
19 part because it resides in a local reliability
20 area. Somebody is going to have to build
21 something in San Diego. It may not be Otay Mesa,
22 it may be Palomar, it may be somebody who hasn't
23 even walked in through the front door yet.
24 But one element of the assumption we're
25 making is that capacity is expanded in a rational

1 fashion. I'm going to get to that in a little
2 more detail as we discuss 2007 and 2013, but
3 fundamentally we assume that whether it's the
4 market or the state or some combination thereof,
5 we're not going to be caught short again. You may
6 quibble with that assumption and we are certainly
7 planning to model a scenario in which an
8 inadequate amount of capacity is built, leaving us
9 perhaps short in 2006 or 2007.
10 But as a baseline assumption, set of
11 assumptions, we believe it's rational to assume
12 that, or logical to assume that whatever the
13 market can't provide the regulator can. No
14 laughter --
15 So, this is the baseline set of
16 assumptions regarding power plant additions in
17 California 2004 and 2006. And, of course, we
18 welcome comment. We expect some.
19 Those additions didn't include additions
20 that we think will result in the renewable
21 portfolio standard. I'm not going to go into the
22 details of the RPS.
23 We think that the capacity required to
24 meet RPS targets through 2006 will be built; that
25 those targets will be met. We also feel, however,

1 that a share of the energy needed to meet those
2 targets is going to come from existing renewables
3 and resources. A sort of back-of-the-envelope
4 estimate that we did showed that over 1000
5 megawatts of renewable capacity might be --
6 existing renewable capacity might be eligible to
7 sign RPS contracts.
8 You'll see that we assumed three
9 technologies would be used to meet the RPS
10 targets, biomass or biofuels, geothermal and wind.
11 We don't want to leave anybody out. Our renewable
12 office has told us that they expect PV solar to
13 meet a small share of requirements.
14 At present we do not plan to model that
15 explicitly in our simulations for a couple of
16 reasons. One, it's very small; and two, it's not
17 that we're lazy, but we don't have a good profile
18 of how PV is going to generate. We might be able
19 to put one together pretty quickly, but we know
20 that geothermal plants generate using a certain
21 daily pattern that really doesn't vary from month
22 to month.
23 We know that wind turbines generate in
24 patterns that have both seasonal and daily
25 variation, as well as geographic. We have quite a

1 bit of data from San Gorgonio, Tehachapi,
2 Altamont. So we can model the daily and seasonal
3 profile of wind units.
4 What we have difficulty doing is
5 assessing how much more efficient new turbines are
6 going to be. The wind turbines in California, for
7 the most part, are ten or more years old.
8 Advancements in turbine technology mean that wind
9 generation is going to be a lot more efficient
10 over the next ten years. How much more efficient
11 is open to question.
12 We have heard from some quarters that
13 our numbers, our capacity factors of 33 to 38
14 percent, depending on whether you're talking about
15 Altamont or Tehachapi or San Gorgonio, are unduly
16 optimistic. We've heard from other quarters that
17 they're unduly pessimistic. So any input you can
18 provide on this would be appreciated.
19 In terms of the profile we're going to
20 use historical data which indicates, for example,
21 that the wind does not blow during the summer and
22 during the afternoon in certain parts of the
23 state. We're going to inflate that profile so it
24 seemingly blows harder, given new technologies.
25 But that's a simplifying assumption we have to

1 make. Again, any input you have to offer on that
2 assumption and how it could be revised, greatly
3 appreciated.
4 Again, a share of the 2006 target is
5 assumed to be met with existing resources. I
6 really can't go into any details about those
7 assumptions because they're based, in part, on the
8 2003 interim renewable procurement proceedings,
9 which are confidential.
10 And finally we show you the amount of
11 output that we think is going to come from new
12 renewable resources under the RPS in 2005 and
13 2006.
14 MS. JONES: David.
15 MR. VIDAVER: Yes, ma'am.
16 MS. JONES: How much of the existing
17 resource from renewable have you included in the
18 resources estimate?
19 MR. VIDAVER: We model, for simulation
20 purposes, all existing renewable generation. So
21 we assume that existing renewable resources, a
22 share of them will continue to generate under QF
23 contracts; a share of existing resources without
24 contracts will be used to meet RPS targets; and a
25 share will have neither a QF nor an RPS contract.

1 MS. JONES: About how many megawatts are
2 you talking about there?
3 MR. VIDAVER: Oh, I couldn't say with
4 any degree of confidence, but probably -- we're
5 talking about 1200 megawatts that don't have
6 contracts, so probably somewhere between 500 and
7 800 megawatts of that would continue forward
8 without a contract.
9 CHAIRMAN KEESE: So, specifically Salton
10 Sea Geothermal is not here because it's contracted
11 to Imperial and won't meet the RPS needs of the
12 IOUs?
13 MR. VIDAVER: Correct. We also do not
14 have a really current handle on how much renewable
15 capacity is going to be built by municipal
16 utilities. We did not assume that the munis
17 participated in the RPS. We've already been
18 proven wrong to some extent. LADWP has announced
19 the intention of bringing 120 megawatts of wind
20 online by next year. SMUD has demonstrated a
21 desire to bring 15 megawatts on as soon as
22 possible, and more later. These are updates that
23 we're going to have to make to our assumptions.
24 Retirements in 2004 and 2006, 2500
25 megawatts. This is a deceptively large number;

1 513 megawatts at Valley, and the 304 megawatts of
2 derates across the Haynes Units are basically
3 going to be offset by repowerings at those sites.
4 With two exceptions, the remaining units
5 are all municipal owned, and they're going to be
6 replaced by newer facilities. Pardon me -- with
7 four exceptions. The Alamitos GT and Etawanda 5
8 are owned by merchant generators. These are units
9 that are going to have to come down under rule
10 2009 of the South Coast Air Quality Management
11 District. They have not installed appropriate
12 emissions control technologies, and the owners do
13 not feel it economic to do so at this time.
14 Hunter's Point, we bring down, it's part
15 of what we refer to as the San Francisco solution.
16 You notice we built peakers in San Francisco. We
17 bring the remaining still operating Hunter's Point
18 Units down. I'm going to talk about San Francisco
19 in more detail shortly.
20 The other major unit that we assume
21 comes down is Mojave. We're talking about 1.5, an
22 estimated $1.5 billion according to some sources
23 that it would take to keep Mojave running. We
24 think it's prudent to bring it down.
25 Yes, sir.

1 MR. MINICK: Dave, I don't disagree.
2 Mark Minick, Southern California Edison, Manager
3 of Generation Planning. I don't disagree with
4 Mojave being removed. The date's wrong; should be
5 December 2005.
6 MR. VIDAVER: Oh, it sure should.
7 MR. MINICK: Yes.
8 MR. VIDAVER: My apologies. Oh, yeah,
9 wow. I don't know how that one slipped through.
10 Yeah, we knew that, Mark, thank you.
11 (Laughter.)
12 MR. VIDAVER: We really did. Yeah,
13 thank you. My, that's embarrassing. Okay, so,
14 these are the retirements that we assume.
15 You're talking about, I thought I had
16 this number memorized, but you're talking about
17 1700 megawatts net plus when you compare the
18 additions and retirements. And that doesn't
19 include the RPS numbers. So, if you toss in
20 another couple hundred for dependable renewable
21 capacity, geothermal and biofuels, you're talking
22 about 1900 megawatts of net increased capacity
23 from the summer of 2003 to the summer of 2006.
24 And if you look at our demand analysis
25 office's demand forecast, you see a growth of

about 4700 megawatts in required capacity, in load plus another 15 percent for reserves. So, we're losing, let's see, do my math here, we're losing about 2000 or 3000 megawatts of reserves over the next two or three years, which we think is reasonable given current low forward prices. They're not so low today, but -- and we remind you that the amount of capacity that was added from the summer of 2003 more than makes up for our not keeping up with load growth for 2004 to 2006.

CHAIRMAN KEESE: Excuse me, before you leave that --

MR. VIDAVER: Mr. Miller.

MR. MILLER: Tom Miller, PG&E. And on Hunter's Point 1 and 4, unless you have better information I think that's still PG&E, not Mirant, as far as the owner.

MR. VIDAVER: Yeah, we knew that, too.

MR. MILLER: Okay.

MR. VIDAVER: Thanks. Why did I decide it was Mirant? I don't know.

CHAIRMAN KEESE: Are these more in the character of firm retirements? These are the --

MR. VIDAVER: Actually, the Valley and Haynes, which are being repowered, are certainly

1 firm. I would include Olive and Magnolia as very
2 firm. In part because we assume that they're
3 being replaced by facilities which are under
4 review. And we believe have every intent of going
5 forward, coming online.
6 The Alamitos and Etawanda units could
7 actually, with the permission of the Air Quality
8 Management District, install the appropriate
9 emissions controls and come back online. So,
10 we're being conservative in assuming that they
11 don't.
12 Hunter's Point is part of a solution.
13 It's a compromise. We don't, given the local
14 opposition to Hunter's Point, we don't feel it
15 appropriate to assume a future in which it
16 continues to operate.
17 Mojave, you'll have to talk to Mr.
18 Minick about what's going to happen with Mojave.
19 I'm sorry. The utility claims that it would be
20 very expensive to allow it to continue to operate.
21 MR. MINICK: It isn't just the expense
22 on Mojave. Mojave has water and coal issues that
23 we have made many filings with the PUC regarding.
24 And until those issues get resolved by the other
25 parties, we think it's imprudent to think that

1 Mojave can't continue.
2 It has a federal abatement order against
3 it that it has to be cleaned up by December 31,
4 2005, to continue operations. At best it would be
5 shut down for a number of years before it could
6 continue to operate. And you can read the PUC
7 filings that we've made on that particular issue.
8 The property is still owned by the joint
9 participants. To say it couldn't be used for
10 something else might be wrong. And Edison's
11 resource plan filing on April 1st will address
12 possible uses of the facility.
13 But at least in 2005 Mojave, as it
14 presently exists, will cease. Whether it's a year
15 or two shutdown and restart as a coal plant, or
16 whether it's a restart as another kind of plant,
17 we can address that later.
18 CHAIRMAN KEESE: Thank you. I'm
19 thinking of two particular areas. The Pittsburg
20 area where I have heard that there might be some
21 plants running into the emissions bubble that
22 could well go offline; and plants, older plants
23 that do not have contracts. They don't
24 necessarily have to shut down, but they may wind
25 up being shut down because there's no market for

1 them to find.
2 Now, is there another list like that,
3 that if it firms up would join this list?
4 MR. VIDAVER: Yes and no. We hesitate
5 to include plants such as those that you've
6 mentioned, or those subject to those conditions
7 on a list of retirements prior to the summer of
8 2006.
9 What history has taught us is that the
10 retirement decision is something that's very very
11 complex, and plants tend to stay in some state of
12 availability, whether it be perhaps on six-months
13 notice, for quite some time after a static
14 economic snapshot would seem to indicate that they
15 should be unavailable.
16 Regarding the possible retirement of
17 those plants from 2007 onward, that's something
18 I'd like to return to later in the presentation.
19 CHAIRMAN KEESE: Thank you.
20 MR. KELLY: Dave, you had indicated
21 earlier, at least from the IOU perspective, you
22 thought they were okay through 2005, which in my
23 mind raised a question about what about 2006.
24 And when I look at your charts for the
25 2004, 2006 baseline additions, those are primarily

1 muni additions.

2 MR. VIDAVER: Yes.

3 MR. KELLY: And when I look at the

4 retirements they're about 50/50 it looks like, or

5 60/40, with a lot of IOU retirements. And from

6 the statewide perspective things might measure out

7 okay, but is there a potential problem from the

8 IOU perspective for 2006 and beyond? How do we

9 stand there on that?

10 MR. VIDAVER: Certainly the residual net

11 short of the IOUs increases gradually over time.

12 It stays, absent considerations of which of their

13 plants might retire, i.e., Mojave, it stays

14 surprisingly low through 2007. It's in 2008 when

15 the DWR contracts are such that all of a sudden

16 there's a substantially greater exposure to the

17 spot market.

18 I'd like to put that aside for a minute,

19 and at the same time refer backward to something

20 that I said. And that is we want to assume that

21 there's kind of a rational expansion of the

22 generation infrastructure. And decisions going

23 forward regarding retirements, or assumptions

24 going forward regarding retirements obviously

25 influence what you assume about what needs to be

1 built.

2 So I sort of like put that aside. It's

3 perhaps the most important question that can be

4 asked here, and I want a chance to offer our

5 approach to that in more detail, and then let the

6 entire audience quibble with it probably in about

7 ten minutes.

8 San Francisco and San Diego, despite all

9 the optimistic sort of rose-colored statements

10 that I've made, the fact remains, as Mr. Kelly

11 pointed out, that while we may be in good shape

12 from a statewide perspective, we have local

13 concerns.

14 In particular there are two areas of the

15 state which require action in the near term. In

16 part because the solution to the local reliability

17 problems that these areas face may be a

18 transmission solution. In fact, it's likely to be

19 one, which means we better get our act together

20 pretty quickly, because it's going to take five

21 years perhaps to actually implement the solution

22 that we come up with.

23 These areas are, of course, San

24 Francisco and San Diego. Now, what we've done is

25 assumed a set of additions, retirements and

1 transmission upgrades that we think doesn't
2 necessarily solve the local reliability problem,
3 but at least alleviates it.
4 And we would very much like input on
5 this, especially from Robert Sparks and the ISO.
6 If the solutions that we proposed are not
7 adequate, and the ISO and other parties think that
8 more needs to be done, we want to know about it so
9 we can put it in our baseline.
10 The San Francisco solution is 180
11 megawatts of peakers located at the airport or on
12 top of the Fairmont Hotel, or somewhere. Increase
13 the transmission -- the transfer capability on the
14 Jefferson-Martin transmission line by 400
15 megawatts. Even though that may have to be built
16 underground.
17 Retire Hunter's Point 1 and 4, which is
18 something that the City of San Francisco would
19 like to see done. And then finally, in 2009 we
20 see the need for additional capacity in San
21 Francisco.
22 The San Diego upgrades include the
23 upgrades at Mission Miguel, increasing the ability
24 to move power from the Miguel substation into San
25 Diego by 500 megawatts. Adding Otay Mesa or

1 Palomar or whatever you assume at the end of 2005.
2 Increasing the south of SONGS transfer
3 capability by 750 megawatts in 2009. This is the
4 Valley-Rainbow project. We don't mean to imply
5 that it will take until 2009 to get done. We
6 don't mean to imply that it won't be needed until
7 2009. This is just what we feel to be a
8 reasonable assumption. If the ISO or anyone else
9 believes that it's reasonable to expect that that
10 upgrade occur sooner, we'd love to know about it.
11 I have two people who -- well, one
12 didn't like what I said and walked out. The other
13 one was kind of curious --
14 (Laughter.)
15 MR. SKOWRONSKI: Mark Skowronski from
16 Duke. If you transfer 750 megawatts from SONGS
17 what happens to the power going north?
18 MR. VIDAVER: It's increasing the
19 transfer capability on the line, allowing power to
20 move south of SONGS into San Diego. It's not a
21 contract which would require the power to do so.
22 MR. SKOWRONSKI: I'm saying I'm sure San
23 Diego and the L.A. area would have basically the
24 same peak at the same time. I mean, are you
25 double counting here?

1 MR. VIDAVER: I don't think so. This is
2 just allowing -- this is an upgrade which I'm
3 probably going to ask Robert Sparks to come up
4 here if I have to get very technical, or Mark
5 Hesters, if he's in the audience -- this is just
6 an upgrade which would allow power to move from
7 the Edison service area south to San Diego. I
8 hope I've characterized that right.
9 Doesn't mean power will actually move;
10 it just -- it reduces the need to keep generation
11 up and synchronous in the San Diego basin, I
12 believe, Encina, et cetera.
13 And finally, in January of 2009 we add
14 415 megawatts of capacity in the San Diego area.
15 The existing South Bay unit, which I believe is
16 owned by Duke, or excuse me, it's owned by -- it's
17 kind of confusing. It's operated by Duke and
18 owned by, I believe, the Port of San Diego. Will
19 have to find a new home. It will have to be
20 retired. And we assume that not only will that
21 capacity be replaced, but an additional 415
22 megawatts or so will be added in San Diego at that
23 time. Any comments on these two are actively
24 encouraged.
25 I want to quickly go over some of the

1 assumptions that we've made about areas outside of
2 California. We presented in our February 13th
3 document a set of assumptions about load growth
4 outside of California.
5 We received load forecasts for areas
6 outside of California from a vendor. This has
7 been revised recently by the vendor. So that the
8 growth rates that were published two weeks ago are
9 no longer those which we're going to assume in our
10 simulations.
11 The vendor has come to his senses and
12 realized that the aluminum industry is dead, so
13 demand in the northwest is going to be lower for
14 the indefinite future. And here you see that the
15 peak demand, unfortunately all we have time to
16 provide was the non coincident winter peak demand
17 in the northwest, has dropped by anywhere from 2
18 and 3 percent in the short run to 1.7 percent in
19 the long run, compared to the previous forecasts,
20 the numbers that we presented two weeks ago. The
21 energy numbers for the northwest don't drop quite
22 that much.
23 We've also revised our numbers for the
24 southwest. Our publication two weeks ago said the
25 southwest was going to grow at about 2.7 percent.

1 That's low. We've revised those numbers upwards
2 to about 3.5 percent. Those may ultimately prove
3 to be too low, as well. But given the higher
4 prices that the southwest is facing during the
5 next couple of years, we think that growth rate is
6 at least reasonable through 2005, 2006.
7 So what this is basically saying is that
8 whatever export potential that the regions outside
9 of California have realized during the past couple
10 of years due to capacity growth is, while not
11 likely to be sustained, those areas are in
12 surplus. The demand, at least in the northwest,
13 is going to stay low for the indefinite future.
14 May I defer to the guest, first? Mr.
15 Kelly.
16 MR. KELLY: Dave, real quick. My
17 understanding is the northwest is even in a more
18 severe recession than we are. Is that steeper
19 curve in the first 2003/2005 reflecting kind of
20 roaring out of the recession at that period of
21 time? Is that what we're seeing there?
22 MR. VIDAVER: Yeah. All the demand
23 forecasts you're looking at now, whether they're
24 for California, the northwest or some other part
25 of the country, and whether they're done by us or

1 someone else, are assuming at some point the
2 economy is going to recover. And the growth rates
3 from the point at which it begins to recover for a
4 couple of years are going to be in -- the demand
5 forecaster will tell you -- but in the 4 percent
6 range as opposed to 2 percent. And then we'll
7 return to normal.
8 So, Mr. Abelson.
9 MR. ABELSON: Thank you, Dave. David
10 Abelson from the Energy Commission Legal Office.
11 On your regional demand forecast for the northwest
12 and the southwest, yesterday during our demand
13 presentation, the issue of whether or not that
14 includes conservation programs going forward,
15 whether or not that includes self gen that might,
16 you know, take off from the main grid system and
17 so on, was a key question.
18 Can you help us understand what
19 assumptions you're using on those issues for your
20 demand in those regions?
21 MR. VIDAVER: I wish I could. As I
22 said, we get these forecasts from a vendor. And
23 this vendor utilizes forecasts done by various
24 entities in the northwest. Among them, the
25 Northwest Power Planning Council, the Northwest

1 Power Pool. So whatever assumptions we're using
2 are basically the assumptions that are being used
3 by those entities going forward.
4 The Northwest Power Pool compiles
5 forecasts from member utilities. There are some
6 40-odd utilities which submit individual load
7 forecasts to the power pool, which the power pool
8 then compiles.
9 Now, I was in a resource adequacy forum
10 in Portland recently, at which the person who
11 compiled these forecasts complained that nobody
12 used a standardized method for compiling their
13 forecasts.
14 So some of the forecasts probably make
15 rather optimistic assumptions about conservation
16 and efficiency; others perhaps ignore it. On the
17 self gen side, that's an issue that we have with
18 the vendor.
19 You have two ways of dealing with self
20 generation. And I'll illustrate this by example.
21 You have a cogeneration facility which is going to
22 build a 100 megawatt plant. And it's going to
23 stop purchasing its power from the utility and
24 it's going to generate it, itself.
25 And it's going to take 50 megawatts of

1 that cogeneration capacity and use it to meet its
2 own load. Well, you have a number of ways of
3 dealing with this. You can add 100 megawatts of
4 capacity to the system, and ignore the fact that
5 the utility is not going to be serving 50
6 megawatts worth of load. Or you can add 50
7 megawatts to the system of capacity and reduce
8 your load forecast by the 50 megawatts that the
9 utility is not going to serve.
10 It's not obvious to us how the vendor
11 deals with this problem. And we've been talking
12 to them about it.
13 So, while we expect self generation to
14 increase, and I believe Lynn Marshall in the
15 demand office made that statement yesterday, we
16 expect it to increase as much in the northwest and
17 in Canada. Alberta's experiencing incredibly
18 volatile prices. If you think California has been
19 a disaster, go to Alberta. They've had -- their
20 annual price volatility is up in the order of 2000
21 percent. They go from offpeak prices of $10;
22 three hours later they're $800.
23 What you're seeing up there is the most
24 of the major industrial facilities, many of which
25 do enhanced oil recovery, are building their own

1 facilities to get away from that price risk that
2 they're facing. And it's a challenge for people
3 who try and assess resource adequacy and do
4 forecasts to track the effect of that generation
5 on load and load forecasts and fundamentally
6 dealing with it in a consistent fashion.
7 So, it's something we're working on.
8 Any real nerds who are interested in this problem,
9 please come up and talk to us. I hope that
10 answered your question.
11 The remainder of the WECC, of course,
12 going to add capacity over the next couple of
13 years, as well. These are our current best
14 estimates, subject to change, of what capacity
15 they're going to add.
16 I spoke with someone in Alberta the
17 other day, a representative of EpCor. He said
18 Genesee is certainly going forward. The second
19 part of Mesquite, again this is a Sempra-owned
20 plant and they have obligations under DWR
21 contracts that are far in excess of the current
22 amount of capacity under their control.
23 TDM, Thermodynamica Mexicali is again in
24 that category. Santan in the Phoenix area, just
25 turned over the first shovel of dirt. Any

1 scenario in which we wanted to assume a very
2 conservative estimate about capacity going forward
3 would remove quite a bit of this.
4 So when we do a scenario in which the
5 amount of capacity added over the next two to four
6 years is below expectations, we will be removing a
7 good share of this.
8 And, again, these numbers will probably
9 change, even for the baseline, between now and the
10 time we actually do the simulations. And if you
11 happen to have any personal knowledge of power
12 plants that are going to come online in the next
13 couple of years in Idaho, please let us know.
14 This is kind a segue, this is our
15 transmission topology. The models that we use
16 assume that load and supply is located in various
17 areas that are constrained with respect to the
18 ability to move power in and out of them.
19 The numbers in red are the upgrades that
20 we're assuming. You can see, for example, the
21 upgrade to the Jefferson-Martin line in the upper
22 left that we assume is going to take place in
23 January 2006.
24 You see the Path 15 upgrade; Path 26
25 upgrade; the dates and the increases in transfer

capability that we're assuming.

The Valley-Rainbow project, or some upgrade to the south of SONGS path. Again, the upgrade at Mission Miguel.

Over in Arizona the path between Palo Verde and the major load centers in Arizona, there are several transmission projects underway. These are our best estimates as to how transmission capability is going to be affected, transfer capability is going to be affected between Palo Verde and the Arizona load centers to the east.

The only upgrade that we have in California that's not currently, at the very least, under discussion is an increase in the transfer capability from the Imperial Irrigation District service area into Edison.

We assume that in 2009 that the transfer capability on this path is increased by 1000 megawatts. We did this to make our RPS forecast internally consistent. We'll talk about the long-run RPS capacity addition assumptions. We assumed that a substantial amount of geothermal capacity in the Imperial Valley is going to be developed over the next ten years. For that to be transferred to the purchasing utilities it will

1 require an upgrade of this particular path.
2 Again, if the ISO wants to weigh in on
3 how much of an upgrade is going to be required,
4 we'd love to hear from them. We understand that
5 they're probably going to have to do that as part
6 of a proceeding later this year, in any case. And
7 we'd like them to keep us apprised of their work
8 in that regard.
9 I mentioned we did not assume any
10 transmission upgrades elsewhere in the WECC beyond
11 the Palo Verde, Arizona upgrade and the small
12 upgrade, I think between Utah and Wyoming. I'm
13 not sure.
14 We're going to add another upgrade.
15 We're going to expand the ability of power to move
16 from western Montana over the Cascades into the
17 load centers along the coast in the northwest by
18 about 600 megawatts, I believe, effective sometime
19 in late 2004.
20 Because of the decline of the aluminum
21 industry and the reduction in loads in various
22 parts of the northwest, it's increasingly
23 difficult to move power from several major
24 facilities in the southwestern Montana/eastern
25 Idaho region, Coal Strip, Libby and Hungry Horse,

it's increasing difficult to move power to load centers in the west. And BPA has asked to upgrade the transmission line increasing the capacity, I think, from 2200 to 2800 megawatts.

I may have the numbers wrong, but for those transmission junkies out there, we're going to model that upgrade. And again, any other upgrades to the transmission system whether in California or outside it that you think we should model, please let us know.

Steve.

MR. KELLY: Dave, it looks like the PUC is moving forward on a Tehachapi upgrade. My understanding is the PUC is at least looking at strongly the Tehachapi upgrade to bring in the wind from that area. And I don't think it's on here, so.

MR. VIDAVER: The topology that we use is not so detailed as to explicitly model the Tehachapi radial line as constrained. I sort of sense the ISO cringing at the thought of not accounting for that. But Tehachapi lies in the same area as the rest of Los Angeles, as far as our model is concerned. So when we add wind capacity in the Southern California Edison service

1 area, we implicitly, if not explicitly, assume
2 that whatever transmission upgrades are necessary
3 to keep that capacity from being stranded are,
4 indeed, -- indeed take place.
5 We appreciate the information. I saw
6 one of our staff write that down.
7 PRESIDING MEMBER BOYD: David.
8 MR. VIDAVER: Yes.
9 PRESIDING MEMBER BOYD: You just
10 ventured into an area that gives me a lot of
11 concern, and that is assumptions that are made.
12 And Mr. Kelly's question just prompted a question
13 that was rattling through my mind as to, you know,
14 the generation of a policy report, which is our
15 responsibility. And a responsibility to identify
16 issues that need to be addressed, and that perhaps
17 have been identified but for days, weeks, months
18 and years and decades, sometimes, have been
19 identified as needing to be addressed.
20 But it leads to my question to you, what
21 level of probability do you assign in your mind to
22 i.e., the success of a project before you find
23 it -- it finds its way onto your chart?
24 And the reason I say that is not
25 complete newcomer to this arena, but before I

1 ended up on the Commission I was locked up in a
2 room with a lot of people for two or three years
3 on the energy crisis. And one of the things we
4 did was, of course, identify Path 15 as
5 desperately in need of upgrade; set out on a
6 project to have that done in the depths of the
7 crisis. Only to have that project, let's just
8 say, aborted by a decision of the PUC to have a
9 then-nearly-bankrupt utility take the
10 responsibility.
11 So, my concern is we have a
12 responsibility in identifying policy issues and
13 the areas that need to be expedited. So, the wind
14 example is another one that's been -- I've been
15 aware of for more than four years now. And yet
16 it's still a problem, et cetera, et cetera.
17 So we have to dice out those things that
18 are policy issues that need to be brought to the
19 attention of the Legislature and the
20 Administration, if not the public. And so we'll
21 have to continue to have that discussion
22 internally.
23 I mean I have pages of questions and
24 underscoring here that I'm not bothering to dump
25 out in the public arena, but there are a lot of

1 these kinds of issues that I think we have a
2 responsibility to identify.
3 So I guess I'm just putting you on note,
4 and others on note, that we have to deal with some
5 of these. But don't forget my question about what
6 degree of comfort or probability level did you
7 assign before you threw it up there with the date.
8 MS. GRAU: With respect to Tehachapi, I
9 just want to point out if you have a copy of the
10 infrastructure report, in table B-9, which is on
11 page B-20, we have all of the Southern California
12 Edison transmission projects. These are all
13 compiled in a table. These are all the ones that
14 the utilities report on a monthly basis the status
15 to the PUC. And it can also be found in their
16 latest transmission plans.
17 And you'll see the Tehachapi
18 transmission line project has a PTO ID number, and
19 they are currently projecting the online date for
20 an upgrade in that area as December 2006.
21 So these are staff's assumptions. The
22 only ones that Dave is talking about are the ones,
23 like you said, that affect the transmission
24 topology, the big ones that affect inter-utility
25 or a few intra-utility lines.

1 So these in the table is a complete
2 listing of everything. And they don't make it
3 into this level, the macro level he's diagramming
4 here.
5 PRESIDING MEMBER BOYD: Well, believe it
6 or not, I read every single page of all these
7 reports, totally ruined a weekend, but -- and I
8 appreciate that. And I just, I guess I'm just
9 saying for the benefit of everybody here, that
10 there are things that need to be pulled out and
11 brought forward out of obscure tables and
12 appendices and made policy issues that we all have
13 to wrestle with.
14 Which is why this and these kind of
15 public sessions are so important. And it's
16 important for people to speak up and point out
17 these little policy nuances that we should be
18 focusing on.
19 So, it's a comment, not a criticism at
20 all.
21 MR. VIDAVER: Not taken any other way.
22 CHAIRMAN KEESE: Dave.
23 MR. VIDAVER: Yes.
24 MR. HUANG: Jeff Huang with Sempra
25 Utilities. I'd just like to point out that

1 there's no physical link between Palo Verde and
2 Los Angeles. The link is actually between Palo
3 Verde and southern California SCE bubble. And
4 then there's a link between L.A. and SCE. But
5 your capacity is correct.
6 MR. VIDAVER: Okay, we'll talk to the
7 person who put this together. And maybe he'll
8 point to the diagram that he drew and show where
9 it matches what you say, and not what I have here.
10 Yes, sir?
11 CHAIRMAN KEESE: Are you moving on from
12 talking --
13 MR. VIDAVER: Please.
14 CHAIRMAN KEESE: I have one question
15 that I would like to raise at some point. And
16 that is one of the obviously identified security
17 risks in California is the security of our linear
18 system electric transmission, which places us at
19 risk. I don't know that we have a report telling
20 us what that risk is.
21 Has there been any consideration of the
22 role transmission augmentation might make in
23 reducing that security risk? Is there any thought
24 of putting that in this report?
25 MR. VIDAVER: To answer the second

1 question first, I don't believe there's been any
2 thought along that line, but Karen Griffin would
3 be far more qualified than I to answer that.
4 CHAIRMAN KEESE: Okay, I'd like to raise
5 it at some time.
6 MR. VIDAVER: The ISO, I'm sure, has a
7 better answer to that question than I do. And if
8 there is anyone in the Commission who can talk
9 about that, a discussion of that issue in a
10 broader context, I would assume it's our office of
11 emergency services in the, I believe it's still
12 called the fuels something office.
13 PRESIDING MEMBER BOYD: Well, on the
14 point that Chairman Keese brought up, one of my
15 concerns is the post 9/11 security issue as the
16 Commissioner who got handed off this allegedly
17 low-key responsibility of being liaison with the
18 Nuclear Regulatory Commission. I am steeped in
19 security now.
20 And so I worry about security of all
21 legs of the, and components of the system. And
22 the question about transmission is a good one I'm
23 quite concerned about. The interaction between
24 the electricity system and other types of systems
25 that fuel our economy such as transportation

1 fuels, which means refineries and those kinds of
2 operations.
3 And those of you, during the crisis,
4 can remember some frantic moments when blackouts
5 were going around, shutting down other important
6 pieces of our infrastructure, and struggles to
7 keep the pipeline flowing, because otherwise we'd
8 cripple the public, et cetera, et cetera.
9 I worry about keeping refineries going
10 and therefore I'm really interested in self gen
11 and cogen, and that's all part of the generation
12 picture. So that, too, is another part of the
13 energy policy responsibility I think this
14 Commission now has to worry about.
15 So, I think it's a good question.
16 That's something we'll have to all wonder and
17 worry about to some degree. It's not just the
18 physical security of a piece of equipment. But it
19 is building in other parts of the system to either
20 back up or assure greater reliability in the less-
21 than-secure times. So, another point well taken
22 that Commissioner Keese has brought up.
23 Just makes your report that much more
24 difficult, doesn't it?
25 MR. VIDAVER: I think I'd like to deal

with your concerns regarding the underlying assumptions that we make and the probabilities that they'll be realized by reiterating that we assume here that with respect to the upgrades needed to operate the system that they occur in a timely fashion between the market and the regulatory agencies that things turn out okay.

And then do sensitivities to illustrate the consequences of getting something wrong.

Going back to the renewable portfolio standard, the additions that we assume. Once we get out to 2006 we assume that all renewable portfolio targets are, incremental targets are met with new capacity. And you can see the megawatt numbers. We assume that most of that capacity is wind, although from an energy perspective it doesn't dominate to quite that extent.

We locate most of this geothermal capacity in the Imperial Valley, as we believe this is where the most potential development lies. A small share of it is located north of Path 15.

Regarding the available wind generation we assume that again most of it is located south of Path 15. We appreciate any comments on the breakdown of this latter number.

1 Again, we assume a capacity factor for
2 new wind generation in the 33 to 38 percent range.
3 Any comments you have on that are welcome. But
4 rest assured that they will be contrasted by
5 someone who believes the exact opposite.
6 So, the amount of generation by 2013 is
7 sufficient to meet the targets that our renewables
8 office says will be in place by 2013.
9 Okay. Now, if 2004 to 2006 was
10 conjecture, 2007 to 2013 is off the chart. There
11 are several ways we can approach the task of
12 building out a resource assessment through 2013.
13 There are models out there which purport
14 to have algorithms which tell you exactly when
15 power plants should be added; exactly when power
16 plants should be retired; and exactly what type of
17 power plants should be added. Whether it should
18 be a gas turbine or a combined cycle.
19 The model we use doesn't have this
20 capability and we don't think we're missing
21 anything. The simple algorithms that estimate
22 optimal addition and retirement basically estimate
23 revenue streams at the facility level. You don't
24 make enough money for one year or two years, you
25 retire. The model shows that it's going to be

1 profitable to operate next year, you build.
2 The world isn't so simple. These types
3 of models ignore the risk associated with not
4 having a long-term contract for output, the hurdle
5 rate to build a plant when you don't have a long-
6 term contract for your output is much higher than
7 it is when you do.
8 It presumes that the price volatility
9 estimates from your model are accurate, or ignores
10 them completely. The more volatile market prices
11 are the more profitable the peaker is. Most of
12 the models which purport to yield optimal
13 investment plans completely ignore this.
14 Finally, most of these models ignore
15 revenue from non energy markets, the possibility
16 of revenue streams from ancillary services, from
17 RMR contracts and for peaking units from capacity
18 payments.
19 And finally, on the side of retirements,
20 they ignore how complex a decision it is to retire
21 a plant. We were told back in 1999 that by 2005
22 the aging capacity in California would be all but
23 gone. And we knew at that time, and we still
24 maintain that capacity from a modeling perspective
25 is not going to drop off the face of the earth.

1 That requires dismantling.

2 And in most cases, even the most aged

3 and most inefficient capacity in our fleet is

4 going to remain around for awhile in some state.

5 It might not generate. It might take two months,

6 six months, come back online.

7 We witnessed during 2000 and 2001 plants

8 which hadn't operated in years all of a sudden

9 surfacing to take advantage of high prices.

10 So we don't feel that in not having a

11 model which analyzed the addition of retirement

12 decisions using some complex black box that we're

13 missing anything. The question then becomes,

14 well, what do we do.

15 As i've stated several times, we think

16 it's prudent to assume that additions and

17 retirements provide the desired level of

18 reliability. That if the market doesn't yield an

19 adequate amount of capacity that the state will

20 step in and make sure that that capacity is built.

21 And the market will not over-provide, either.

22 This approach does not assume any

23 particular role of the state in electricity

24 markets as we move forward. It's compatible with

25 a market in which the state plays virtually no

1 role. And private development produces all
2 necessary capacity.
3 It's also consistent with the role where
4 private development is eliminated and the state
5 does everything. So I don't think we need to get
6 into a philosophical debate about which is more
7 efficient.
8 So, that being said, the question then
9 becomes how much capacity yields the desired level
10 of reliability. And we realize that that depends
11 largely on not only the functioning of the market,
12 but regulatory decisions which have yet to be
13 made, and perhaps even yet to be thought about.
14 We propose using reserve margins that
15 prevailed in 1998 and 1999 as sort of a target to
16 which the system will return over the long run,
17 and then remain as we move forward.
18 The first question then is, well, pick
19 one, damn it, 1998 or 1999. It's not that easy to
20 do because the peak in 1998 was something like a
21 one-in-five-year peak, and the peak in 1999 was
22 like a four-in-five-year peak. So it requires
23 some degree of interpolation.
24 Perhaps even those reserve margins are a
25 little too high. As we build new capacity which

1 has forced and maintenance outage rates that are
2 quite low, the fleet becomes far more efficient,
3 in which case we might need less capacity than we
4 did ten years ago.
5 So, that's what we propose to do, is
6 look on a transmission area-by-transmission area
7 basis at how much capacity and retirements return
8 us to conditions that prevailed in 1998 and 1999.
9 Some degree of flexibility is required. For
10 example, during those years prices north of Path
11 15 were higher than prices south -- higher than
12 prices south of Path 15. Indicating that during
13 those years there was perhaps a need for more
14 capacity in the northern part of the state.
15 So, what we propose to do is look at the
16 results that our initial baseline runs yield in
17 terms of prices, and reliability, and modify it to
18 take into account certain anomalies that would
19 prevail if we return capacity margins to 1998 and
20 1999 levels on a transmission area specific basis.
21 The ultimate reserve margin will depend
22 on what regulators do in response to the market.
23 It could be that the reserve margins in 2010 will
24 prove to be much higher because of a risk-averse
25 attitude adopted on the part of regulators. They

1 could prove to be much lower because of an
2 efficient regulatory regime and a relatively
3 efficient market.
4 We don't propose to know the answer to
5 that question. We do propose that when you see
6 our baseline and you see our numbers to comment.
7 Yes, sir.
8 MR. ABELSON: Of the various historic
9 timeframes you might have used as your target for
10 reserve margins, what was it that caused you to
11 focus on the two years of '98 and '99?
12 MR. VIDAVER: Well, let me -- more
13 recent years. If we go back to the reserve
14 margins we had in 2000, you're walking a
15 regulatory tightrope. You've getting prices which
16 are indicative of the ability of generators to
17 exercise market power.
18 It would require the assumption that an
19 appropriate regulatory monitoring function be in
20 place that prevents that from happening.
21 You may ultimately be right; that may be
22 the equilibrium -- pardon me, I was trying to --
23 that may ultimately prove to be the equilibrium
24 level of reserves. It could be that that amount
25 of capacity, despite the ability of generators to

1 manipulate the market, will be in the future the
2 amount of capacity and the size of the reserve
3 margin that will prevail, with a little better job
4 on the part of state and federal regulators
5 controlling the exercise of market power and
6 manipulation in spot markets. So, 2000 certainly
7 is an alternative.
8 By 2001, given all the conservation we
9 observed, the system is over-built. By 2002, even
10 moreso. Going back to 1995, '6, and 1997 the
11 system was obviously in surplus. Although quickly
12 heading toward disaster. But those reserve
13 margins would be far too high. The simulations
14 that we've run indicate that the prices that come
15 out at those reserve margins don't sustain
16 developers.
17 DR. ARTHUR: Dave Arthur, the City of
18 Redding Resource Planner. I have to confess I'm
19 slightly astounded that one would select 1998 and
20 1999. That was, I take it, what we actually had
21 and two years later we had a disaster where we had
22 shortages. We were not able to respond to a
23 sudden growth in the economy at that level of
24 reserve margin. We were not able to respond to a
25 drought that occurred coincident with that.

1 I can't imagine that one would select
2 that reserve margin, having gone through what is
3 arguably a $20- to $40 billion experience that
4 cannot be survived a second time.
5 I would hope that we have a reserve
6 margin that is adequate to address the unexpected
7 growth in the economy; to address droughts which
8 are not predictable; and address other kinds of
9 contingencies that can come along under Murphy's
10 Law at the least convenient time.
11 And if we learned anything it seems to
12 me over the last few years it's that having a
13 little too much is not a serious problem. But
14 having too little is very very serious. And
15 unfortunately, I don't see that kind of thing
16 being addressed.
17 PRESIDING MEMBER BOYD: Well, I --
18 CHAIRMAN KEESE: I'll just --
19 PRESIDING MEMBER BOYD: Go ahead.
20 CHAIRMAN KEESE: -- comment, since the
21 circumstances of 1998, which led to the
22 Commission's analysis that we were going to have a
23 problem and which we, our staff pointed out in
24 early 1999, and we tried to sell to people with
25 limited success.

1 I would agree with you that we can't go
2 back to the situation we had in '98 because in
3 1998 we had absolutely no infrastructure on the
4 horizon, and we had a timeline of almost five
5 years to get it started.
6 My analogy is I presented was we were --
7 the airplane was going down and it wasn't starting
8 very high. We anticipated that by the year 2000
9 if everything had just stayed the same we would
10 have a zero reserve margin.
11 So I think we can say the reserve margin
12 was adequate; it was the rest of the system that
13 didn't have it on a level course, had it going
14 straight down.
15 So, if I had to pick I would say I think
16 we are in the right at '98 or '99; we'll have to
17 look at it. Are you giving us a number?
18 MR. VIDAVER: Am I giving? Oh, no.
19 (Laughter.)
20 CHAIRMAN KEESE: You're just going to
21 say '98 or '99?
22 MR. VIDAVER: Yeah. No, we're not going
23 to give you a number. We'll give you a number at
24 some point. I just --
25 CHAIRMAN KEESE: You're going to give a

1 range sometime?

2 MR. VIDAVER: Yeah. Tom, I'm sorry, I

3 just want to make one comment to Dave. And that

4 is one of the purposes of the scenarios that we're

5 running is we're going to run low hydro, booming

6 economy scenarios. And what they will yield, if

7 you're correct, is that we'll have problems, which

8 indicates then, okay, the 1998 reserve margins are

9 not suitable. And at which point we should

10 probably go back and revise the baseline along the

11 lines that you suggested.

12 So I hope that assuages some of your

13 fears.

14 MR. MILLER: This is Tom Miller, PG&E,

15 again. David, I was wondering if you could

16 explain how you implement your method for Path 26,

17 where there was, you know, considerable buildout

18 of generation and a change from the '98, '99

19 period as far as reserve margins?

20 MR. VIDAVER: That's a -- you could help

21 us answer that question. Path 26 is unique in

22 that it's in the central part of the state where

23 you have a whole lot of power plants and nobody

24 lives there, except control room engineers, I

25 guess.

1 And assuming you have enough capacity
2 along Path 26 which sends energy south, and Path
3 15 which sends it north, Path 26 is really kind
4 of, it's a nonentity. It doesn't really impact
5 anything. So, in deciding -- a case could be made
6 to not locate any generation in ZP26. Just to see
7 what happens.
8 Because if you have a lot of capacity
9 south of Path 15, and not enough north, you get
10 congestion along one path going north, and vice
11 versa, you get a congestion along another path
12 going south.
13 So, I'm not sure the decision about
14 where to locate -- and please correct me if I'm
15 wrong, and I'd like Mr. Sparks to do the same
16 thing -- the decision about how much capacity to
17 place in ZP26 is not nearly as significant as the
18 decision whether to place capacity south of it or
19 north of it.
20 One of the considerations was that it
21 seems to be a popular place to locate power
22 plants. And that as such, we might as well
23 continue to locate them there.
24 MR. MILLER: The reason I asked because
25 if you are determining the reserve margin on a

1 transmission area basis, and ZP26 being a
2 transmission area, then if you see no need, I mean
3 in other words the reserve margin didn't decline
4 from the '98/99 period, you might, in effect, have
5 a cushion, the reserve margin because of the
6 generation built out there.
7 MR. VIDAVER: Yeah.
8 MR. MILLER: Is that true?
9 MR. VIDAVER: Yeah, because -- maybe I
10 can answer this another way. We don't really
11 worry about the reserve margin in ZP26. We worry
12 about the reserve margins north of Path 15 and
13 south of Path 15 and assume that what we build in
14 ZP26 contributes to those reserve margins in those
15 areas as long as those paths are not congested.
16 When they become congested we then take
17 a look at them more carefully.
18 MS. JONES: David, can I just -- I have
19 a related question about transmission. Wouldn't
20 it be valuable to do a scenario in which you have
21 the generation additions, but since, in effect,
22 there are no transmission, major transmission
23 upgrades going forward, none have been approved,
24 wouldn't it be important to know what the
25 implications of not expanding our transmission

1 system are on the electricity system?
2 MR. VIDAVER: I think that certainly
3 would be a useful thing to do. My only
4 observation would be that there might be,
5 depending on the questions you wanted to ask,
6 there might be better tools to use.
7 For example, if you wanted to ask how
8 prices would differ across transmission zones. It
9 would be a very useful thing to do. If you wanted
10 to ask are there going to be problems during peak
11 hours with system reliability, there might be
12 better models to use such as power flow models
13 that look at the ability of the system to deliver
14 energy under adverse conditions during peak hours.
15 So the answer to your question is it
16 would be -- yes, it would be a good thing to do,
17 but you have to keep in mind that depending on the
18 questions you want to answer there might be better
19 tools.
20 So that would be a scenario that we
21 could certainly run. For example, what if you
22 didn't expand Path 15.
23 MS. JONES: Thank you.
24 MR. SKOWRONSKI: Yesterday we covered
25 basically demand, what the IOUs and everybody will

1 be needing. And today I guess we're covering
2 generation. But I don't see the marriage here
3 with respect to, you know, what's the bottomline.
4 When do the lines cross? Various scenarios of
5 demand and various scenarios of generation. Do we
6 have any finality here with respect to matching
7 the generation with the demand?
8 MR. VIDAVER: Well, we're choosing the
9 set of supply assumptions so as to look at the
10 effect of those assumptions given the demand that
11 was talked about yesterday on such things as
12 price, both generally and by transmission area.
13 The variables that affect -- demand is
14 sort of the driver. You have to have a good
15 demand estimate before you know what supply is
16 going to be. Because only enough supply is going
17 to be built in a rational world so as to meet
18 demand.
19 So in a sense you kind of have to start
20 by dealing with them separately. And all the
21 uncertainties here about what the appropriate
22 baseline is, and what the appropriate adjustments
23 are to it when you run scenarios bring supply and
24 demand together.
25 MR. SKOWRONSKI: That's my point. I

1 mean do we have a slide that actually shows that?
2 I'm just kind of fuzzy of how the generation and
3 how the demand lines are meeting. I see a lot of
4 different scenarios, but do we have a baseline
5 assumption or recommendation or --
6 MS. GRIFFIN: I'm Karen Griffin; I'm the
7 manager of the overall project. That's the next
8 step. If we work through the demand assumptions
9 and then the supply assumptions, and the natural
10 gas assumptions, and transmission, and the next
11 step is a set of analysis that we call supply
12 adequacy.
13 So as we finish today then staff will go
14 back and start working on that product.
15 MR. SKOWRONSKI: Okay.
16 MS. GRIFFIN: And will be bringing that
17 back to the Committee, and the product in the
18 early spring.
19 MR. SKOWRONSKI: All right, thank you.
20 MS. BAKKER: Actually now that surprises
21 me because what it looks like in David's graphs
22 is, and maybe I'm just not understanding it, that
23 you've used the estimate of revenue streams to
24 decide what additions to add. And that that's
25 where we got 2007 through 2013. And that you've

1 already added your resource plan.
2 MR. VIDAVER: I've added the resources,
3 well, I proposed a decision role to add resources
4 based on 1998/1999 reserve margins. But the
5 impact, or the results of that assumption, as Mr.
6 Arthur said, still need to be tested. And that's
7 the purpose of doing the scenarios.
8 We have not looked at the profitability
9 or lack thereof of specific power plants. For
10 example, the generic combined cycle. We haven't
11 looked at the prices in say 2009 and said, oh,
12 combined cycle could make money this year, so
13 we'll add one. We have not done that type of
14 analysis.
15 MS. BAKKER: Okay, well, what's
16 confusing then is the two slides following this
17 which actually show additions from in California
18 and in the rest of the west.
19 MR. VIDAVER: Yeah, these are the
20 capacity additions necessary to sustain reserve
21 margins at the 1998/1999 levels. So if we're
22 going to decide --
23 MS. BAKKER: Okay, so you actually do
24 have a number then, don't you?
25 MR. VIDAVER: 4,065, yeah.

1 MS. BAKKER: No, no. Percent.
2 MR. VIDAVER: Oh, do I have any idea
3 what the reserve margins are?
4 MS. BAKKER: Yeah.
5 MR. VIDAVER: Yes. Do I have a number
6 written down right here that I'm going to share
7 with Commissioner Keese?
8 (Laughter.)
9 MR. VIDAVER: No. No, I got the
10 impression that the Commissioner was asking for
11 some number between 7 and 30 that I knew. And to
12 be quite honest, I don't. I don't know what the
13 reserve margin was, off the top of my head. I
14 could go calculate it, and then say what it is,
15 and watch everybody debate whether or not that
16 number was indeed accurate.
17 MS. BAKKER: But it was the 98/99
18 number?
19 MR. VIDAVER: Well, yeah, that I think
20 is a relevant number, but it's not one that I
21 can -- if I said 24, pulling a number out of the
22 air, a good share of the audience would probably
23 go 24? Oh, that's way too much capacity. We
24 don't need that. Deregulation must have failed.
25 And if I said 7, I imagine people would

1 come running over from the Power Authority en
2 masse and say, oh, we can't live with that.
3 So, I hesitate to say what that number
4 was. Because even though we can calculate it, it
5 has an emotional content that there are different
6 ways to calculate it, and --
7 MS. JONES: So, just to clarify what
8 we've got up here, did you just basically take
9 demand or peak demand and then subtract out what
10 you've got in the system and the retirements and
11 all to come up with these additions? This is just
12 a simplistic assessment and it doesn't have --
13 well, it has an implied reserve margin?
14 MR. VIDAVER: Yeah, that's exactly what
15 we did.
16 PRESIDING MEMBER BOYD: I appreciate
17 what David's saying and we don't want to debate on
18 the number. He's right, he'd become a target
19 suddenly. But now everybody's going to run out
20 and back-calculate based --
21 MS. JONES: Yeah.
22 PRESIDING MEMBER BOYD: -- their '98 --
23 MS. JONES: Because I could do that
24 calculation.
25 MR. VIDAVER: But they have to use our

1 numbers. That's --

2 PRESIDING MEMBER BOYD: But at least

3 they'll do it outside of this room, and debate

4 with themselves. And I appreciate the weaknesses

5 and strengths of the years '98 and '99. My first,

6 I mean it was the heat storm year, was this, that

7 and the other, but absent a lot of other

8 testimony, you know, and greater -- probably for

9 an academic discussion, a halfway decent place to

10 start.

11 I just want to comment on something that

12 was stated earlier, thought, in that debate about

13 the 98/99, and that was well, that couldn't have

14 been a good reserve margin because the sky fell on

15 us shortly thereafter. Well, the sky fell for a

16 lot of other reasons.

17 One of the issues we face now, since we

18 came out of a regulated monopoly where you

19 dictated and assured what the reserve margin would

20 be, and lots of people in the state thought

21 electricity was too expensive in California, among

22 all the other reasons for deregulating.

23 We're now in that hybrid area of trying

24 to figure out, you know, who will pay, and how do

25 you pay for adequate reserves, and once you set a

1 target. So that's another policy dilemma that a
2 lot of people are still trying to deal with.
3 But the people who are dealing with
4 that, including this organization, are the people
5 who are trying to rebuild the ship that burnt to
6 the waterline, and decide where to set sail next
7 time around.
8 I keep thinking of that Viking King who
9 built the most magnificent warship ever seen, and
10 kept changing it. And his people didn't have the
11 courage to tell him he was maybe, you know, all
12 these changes he wanted might not go. So they
13 built the ship and they set sail and it sunk in
14 the harbor. And they dredged it up here recently.
15 Now it's a great display in Stockholm.
16 But, I mean that's the same committee
17 who built our restructuring thing, I think.
18 Anyway, I don't want to get off on that.
19 (Laughter.)
20 PRESIDING MEMBER BOYD: David, you don't
21 have to keep defending yourself. I appreciate
22 your dilemma here.
23 MR. DeSHAZO: I'm Gary DeShazo with
24 California ISO. And maybe perhaps the
25 conversation has sort of moved beyond where we

1 were when I first got up. But, since I made the
2 effort --
3 PRESIDING MEMBER BOYD: No, it's
4 relevant.
5 MR. DeSHAZO: -- I'll go ahead and --
6 PRESIDING MEMBER BOYD: Please do.
7 MR. DeSHAZO: -- there were a couple of
8 questions that were asked. The ISO, you know,
9 sort of continues to come up in the conversation.
10 And that's a good thing because that's what we
11 want to have happen.
12 But I think that maybe going back to a
13 comment that I heard you make a little bit earlier
14 about the balance of the resource against the
15 transmission. And then the comment that you had
16 made about, well, maybe we should just not assume
17 any transmission building at all and see what the
18 resource would be about that.
19 And at least in my mind, from a
20 perspective of trying to find the best way to make
21 sure that we have a reliable system, and that we
22 can serve the load in our state, it's really the
23 balance between those two.
24 And I think that what has just occurred
25 in the discussion is what has always been the

1 basis of that conversation is trying to figure out
2 how that is done.
3 Now, we've got a planning process.
4 You've got a resource acquisition process. You've
5 got a load forecasting process. And in my mind I
6 think the real question is how do those things get
7 matched up, so that what you end up with is
8 something that is worthwhile, is buildable, and at
9 a reasonable cost.
10 I think that's the overall key. And at
11 least from the ISO's perspective and the process
12 that you're getting started here, I guess, we view
13 that as a way to start that conversation and see
14 where things end up. And so provide us the
15 opportunity for the input and we'll see where
16 things go.
17 But that was the comment that I was
18 interested in making at the time the questions
19 were asked.
20 PRESIDING MEMBER BOYD: Thank you.
21 CHAIRMAN KEESE: Let me ask one
22 question. You're talking about this is the
23 additions to demand?
24 MR. VIDAVER: These are --
25 CHAIRMAN KEESE: Or are you -- is this

1 what has to be built in those territories?
2 MR. VIDAVER: This has to be built in
3 these areas to maintain reserve margins at
4 1998/1999 levels.
5 You can see that we're --
6 CHAIRMAN KEESE: And are you assuming
7 historic import factors?
8 MR. VIDAVER: The reserve margin
9 calculation that we're doing excludes imports from
10 consideration. It's still on the ground in
11 California or owned by California entities outside
12 the state.
13 CHAIRMAN KEESE: Okay, so for example,
14 if you need 500 megawatts in the Southern
15 California Edison territory in 2008, it might be
16 built in Arizona?
17 MR. VIDAVER: No. We're assuming that
18 the reserve margin is based on steel in the ground
19 at that location. So, when I say 150 megawatts in
20 Southern California Edison in 2007, that's where
21 the plant is being built.
22 Now, remember this is an assumption for
23 a simulation, a computer-driven simulation. In
24 reality, that 150 megawatts could be provided by a
25 plant in Utah owned by a merchant generator who

1 has a 150 megawatt 7-by-24 firm contract with
2 Edison. In reality.
3 So, one --
4 CHAIRMAN KEESE: Okay.
5 MR. VIDAVER: -- one of the caveats
6 about this is that the reserve margin, several
7 caveats, but one is that the ultimate reserve
8 margin is going to depend on, for example, the
9 extent to which regulatory authorities allow
10 contracts from out of state to meet resource
11 adequacy requirements.
12 Another caveat is that should regulators
13 allow, be flexible in determining what resources
14 can be used to meet resource adequacy
15 requirements. Capacity can be built well outside
16 the state.
17 As the gentleman from the ISO just
18 stated, if the incentives exist to expand the
19 transmission system, and we have a transmission
20 pricing scheme which incents building generation
21 in remote areas, and using wires to get the power
22 to load centers rather than gas pipelines, you
23 will have a much different set of resources being
24 added than you would had you encouraged -- had you
25 adopted, for example, another transmission pricing

1 scheme, or not expanded the transmission system to
2 the extent that you would have liked. And forced
3 or incented generators to be built next to load
4 centers.
5 So, this is a very very simple rule of
6 thumb that can, in a geographic, can vary
7 dramatically depending on regulatory outcomes that
8 we have no knowledge of.
9 CHAIRMAN KEESE: I guess I'm comparing
10 it to my very simple thumbnail rule that we need
11 about 2 percent more a year so that's somewhere in
12 the area of 1000 megawatts a year.
13 MR. VIDAVER: What you see here is you
14 see the 1000 megawatts a year starting in about
15 2009. This is indicative of the fact that given
16 the capacity that we've added to date, and the
17 capacity that we expect to be added today and the
18 capacity that we expect to be added through 2006.
19 There won't be a need for any in 2007
20 and '8, at least to meet the reserve margin
21 criteria that we're using as a decision rule.
22 CHAIRMAN KEESE: Thank you.
23 MR. TOMASHEFSKY: That's right. Now
24 from a policy perspective the question then
25 becomes given if that's the profile we need, what

1 happens that might affect whether we can get that
2 in the first place. And then that's where we run
3 into the situation where you choose a different
4 reserve margin estimate, whatever that '98 or '99
5 number is. You may need considerably more and you
6 may not have the policies that would allow that to
7 actually occur. So that's where this number then
8 becomes important.
9 MR. VIDAVER: Yeah, certainly the higher
10 the reserve margin you need, the, in some sense,
11 the more dramatic the set of policies you need to
12 achieve it. So, in that sense, yes, that's
13 certainly true.
14 MR. KELLY: Yeah, I just have a general
15 question -- or comment, actually. It kind of
16 feeds off from my comment yesterday when we were
17 talking about the demand, and I think it builds
18 off what Commissioner Boyd was talking about.
19 Yesterday we were talking about demand
20 and how do you treat committed demand and
21 noncommitted demand. And the question that I had
22 really was how do you know something is committed
23 or not committed.
24 And I think one of the things in
25 developing a baseload, the baseload from which we

will develop scenario studies to drive the policy decisions, the baseload planning, what I think is missing in the report is, in my mind at least, is clarity about what are the standards or the criteria to determine if something goes into a cell that generation is going to be there, or demand will be there.

I get the sense I'm being asked to comment, for example, is there going to be 800 megawatts geothermal. I have no idea if there's going to be 800 megawatts of geothermal. If you ask me to comment should you include it in your study that we're going to count it as committed once they've filled an AFC, then I can respond to that. And I can answer yeah, that makes sense to me. And we shouldn't do it off a letter or a phone call from some guy out in, you know, south Burney.

Those kinds of things and those standards and criteria for determining how you're treating the indiscrete -- there's discrete variables is something that I think is missing here. And I'd like to see maybe a chapter or some place bring that out so that it would make it easier for stakeholders to comment that is

1 reasonable or that is not reasonable.
2 And then those factors will drive, I
3 think, whatever numbers are fitting into these
4 cells. And quite frankly, it's very impossible
5 for me to respond to what in the cells, but I can
6 talk about factors and whether it's reasonable or
7 not.
8 I'd recommend you thinking about
9 structuring the report to do that on the baseline.
10 And then the next step would be all right, let's
11 do some scenario planning that's going to drive
12 policy decisions. What if you do this or this?
13 Do we have enough capacity to meet a preferred
14 reserve margin.
15 That's kind of how I think this report
16 process might be helpful over the next four or
17 five months if we get a good understanding what
18 the baseline is.
19 Just a comment.
20 PRESIDING MEMBER BOYD: Well, I think
21 it's -- I appreciate the comment. I mean when I
22 got done reading all this and trying to understand
23 it I kind of felt like this is going to be a tough
24 couple of days, because we have half a loaf.
25 And we've already talked about we're

1 going to provide the other half of the loaf a
2 little later down. And then have everybody back.
3 This is not meant as a criticism. It's
4 taken all the bakers that we have at our disposal
5 in this organization to get us this far. And I
6 think the workshop is proving extremely valuable.
7 The staff is trying to -- and we, we're
8 trying to tease out of the experts in the audience
9 any of those factors and points that should be
10 included as we move farther down the line.
11 And then the next time we have a
12 workshop I think we'll have a more mutually
13 educated view of where we're going.
14 But I mean, we have to do what we do and
15 it's tough. I mean this is a tough couple of days
16 to deal with this because we aren't dealing with
17 everything out on the table. And the staff is, I
18 think, trying to get as much help as they can from
19 all of you. And I'm sure each successive day
20 there will be more and more interaction with
21 folks, vett some of the assumptions and what-have-
22 you.
23 But we are crying out for help in terms
24 of your knowledge and views of this issue. It's
25 been a long time since people sat down to do this,

1 I'll bet, if anybody's tried to go as far as I
2 think this conceivably could go, after surviving
3 the wreck of the past couple of years. So, in
4 defense of where we're trying to go.
5 I agree with the gentleman from the ISO.
6 When we get all done we have to plug this back
7 into some system that is kind of -- I know models
8 are good tools; I like models for tools. But,
9 god, we depend on them to make decisions that they
10 can't make.
11 But, nonetheless, we have to establish
12 all the various criteria parameters and try to get
13 them as much agreement on those before finally
14 cranking out the system to balance the system; do
15 you do transmission, do you do generation,
16 policywise, how much self gen, cogen can you
17 tolerate. All of this in the environment of we
18 have a mortgage to pay off, and rules and
19 regulations relative to making sure we pay off
20 that mortgage.
21 So, et cetera, et cetera. As we keep
22 adding more factors this is going to get even more
23 difficult, and David's life is going to be even
24 more challenging, let's just say.
25 And I want to -- I just want to comment

at this juncture that I'm appreciative of the fact that we have advisers up here with us. My Adviser, Susan Bakker; Scott Tomashefsky with Chairman Keese, and particularly Melissa Jones who is sitting in for Commissioner Geesman, who is intensely concerned with and involved in the transmission question. And would have sat here with us, could he have, and I appreciate the fact that Melissa is here watching out for the transmission piece for us. Because it is part of the three-legged stool that this thing's going to sit on. Transmission, generation, et cetera, et cetera, so, anyway, must be getting close to lunch or something.

But, David, you have to finish.

MR. VIDAVER: I have to finish -- I was going to try and address a couple of Mr. Kelly's concerns beyond saying that I think it --

PRESIDING MEMBER BOYD: How much more time do you need, David?

MR. VIDAVER: Probably, to do it justice probably a little more than our stomachs will allow.

PRESIDING MEMBER BOYD: Twenty minutes? Half an hour? An hour?

1 MR. VIDAVER: Okay, well, you throw me
2 out of the room when you get tired of listening to
3 me.
4 PRESIDING MEMBER BOYD: Do you need 20 -
5 - can you do it in 20 minutes?
6 MR. VIDAVER: Twenty, probably. I'll --
7 yeah, if people don't interrupt, yeah.
8 PRESIDING MEMBER BOYD: It would be nice
9 to finish.
10 (Laughter.)
11 PRESIDING MEMBER BOYD: All right, it
12 would be nice to finish this rather than break in
13 the middle.
14 MR. VIDAVER: Yeah, okay. Just quickly
15 I want to respond to what Mr. Kelly said. As far
16 as the short timeframe in which we have a
17 reasonably good, yet not nearly good enough feel
18 for what's going to transpire, I think scenario
19 analysis is -- we do a baseline where we put in
20 Otay Mesa and Metcalf, and then we yank it out,
21 because it's quite plausible that it won't come
22 online, and we see what happens.
23 In a longer run when nothing is
24 committed as of right now, we have to use a set of
25 rules for devising a baseline. And the presence

1 or absence of commitment certainly can be one of
2 them, as I'm sure you'll agree.
3 Going back to what Dave Arthur said,
4 maybe what we do is we adopt a set of decision
5 rules and then see how sensitive the adoption of
6 that rule is to, you know, can we deal with a
7 drought and a heat storm in one year if we make
8 this set of decisions. Even answering that
9 question is taking a long step forward and useful
10 in deciding whether or not you've actually come up
11 with an appropriate baseline.
12 These are the California additions that
13 we assume. These numbers are not final. We're
14 going to be tweaking them. Most likely we're
15 going to move capacity out of I should say SP15,
16 and into NP15.
17 So the total quantity is probably pretty
18 accurate, but we're going to, as we do simulation
19 runs, and look at the results, we're probably --
20 my guess is we're going to move some capacity out
21 of southern California and into northern
22 California. We're seeing a price differential
23 between the two regions with this set of additions
24 that we're not real fond of. And one that we
25 don't think the market could sustain over a long

1 run. People would build capacity in northern
2 California with those price differentials.
3 A set of capacity additions for the
4 remainder of the WECC. What they indicate is that
5 the southwest has done a good job of paving itself
6 over. And the northwest has not. The Northwest
7 Power Planning Council sees itself as possibly
8 being short; having unacceptably high
9 possibilities of curtailing load in 2006/2007.
10 And the numbers that we come up with for capacity
11 additions there reflect that concern.
12 So Baja, California is another area that
13 we would like advice on. We expect that that
14 region is going to grow substantially. But the
15 amount of capacity being added there is quite
16 substantial. We're not sure that 500 megawatts is
17 apt to be all that we see down there over the next
18 ten years, even if that gets us back to an
19 adequate reserve margin. Or back to a reasonable
20 reserve margin, I should say.
21 Not so loose ends. We would like some
22 input on how to -- when we add new capacity we
23 have a choice of the type of capacity to add. And
24 I'm not really referring to renewable,
25 nonrenewable. We do need to refine our

1 assumptions about renewable non-RPS capacity
2 that's liable to be added outside of California.
3 PacificCor in their resource plan said they're
4 looking to subscribe to anywhere between 500 and
5 2000 megawatts of wind capacity that does not
6 exist in the northwest over the next several
7 years.
8 We do not assume that that amount of
9 capacity is going to be added, and we should. The
10 reason we don't assume that is, one, we don't have
11 very good information on the resource development
12 potential in the northwest and he likelihood that
13 large amounts of wind capacity are going to be
14 added.
15 The second reason is we don't know how
16 wind generators in the northwest perform. We're
17 talking about confidential data. We do know that
18 they don't perform with a seasonal and daily
19 profile that they have in California. That
20 they're far less cyclical. But there is a dispute
21 as to how efficient new wind turbines are in the
22 northwest. The statements of developers seem to
23 be optimistic compared to the real live
24 performance from existing wind units in the
25 northwest and we want to resolve that difference

1 before we explicitly model new renewable capacity
2 there.
3 What this is referring to is do we add
4 baseload or peaking capacity. Because we are not
5 using a methodology which is amenable to screening
6 curves and analyzing revenue streams of generic
7 new combined cycles and peaking units, we need to
8 come up with another way to say, okay, enough
9 baseload, we should be adding peaking capacity.
10 And what we propose to do is establish a
11 sort of threshold capacity factor for combined
12 cycles. And once the new combined cycles in a
13 transmission area reach that capacity factor
14 assume that one more combined cycle would not be
15 built because it simply would drive the capacity
16 factor of the other plants too low. And all
17 incremental capacity added in that area be peaking
18 capacity.
19 If anybody has a suggestion as to
20 another way to look at this, another way to make
21 this decision, speaking to the modeling nerds,
22 please let us know.
23 And the biggest concern. The state, as
24 everyone is fond of pointing out, has a lot of
25 very old capacity. It's not as old and not as

1 dispensable as people would like us to believe.
2 There's been a substantial number of repowers.
3 Operators obviously anticipate going forward for
4 some time. At least those who have installed SCR.
5 Some older plants actually have RMR contracts.
6 Some actually have DWR contracts.
7 So, the notion of which plants are apt
8 to disappear presents a series of difficult
9 questions. And staff hesitates to unilaterally
10 retire large quantities of capacity simply because
11 it's old, and simply because it's inefficient.
12 However, we do realize that this is
13 going to take place. From a modeling perspective,
14 and I know those of you who aren't modelers will
15 find this difficult to believe, it really doesn't
16 matter. Because when a plant gets inefficient
17 enough it just sort of stops running.
18 And if you can imagine a 1500 megawatt
19 behemoth acting like a peaker that just can't
20 quite respond as quickly but nevertheless it's
21 only used during the summer, a prolonged exposure
22 in a modeling environment sort of absolves you
23 from having to make these decisions.
24 Now, what failing to retire these plants
25 does is it makes, well, one thing it obviously

1 does is excuse your reserve margin. So if you're
2 using that as a criteria and you decide whether or
3 not to add plants, your inclusion of aging
4 capacity reduces the amount of new capacity that
5 you add. However, what it does do is -- or what
6 it doesn't do is affect that capacity factors of
7 those new plants.
8 So, in a sense, if you're looking at
9 about 8000 hours of the year it doesn't matter
10 whether you add or you retire aging capacity.
11 Unfortunately, when you look at the
12 other 400 to 800 hours your decisions about what
13 plants to retire are affected.
14 So what we would like from the modeling
15 community is some assessment of is it necessary to
16 adopt a decision rule regarding the retirement of
17 older capacity. Can anybody, like somebody's
18 actually set foot in a 50-year-old power plant,
19 tell us what power plants are apt to retire or
20 not. We think we have -- we know which criteria
21 we should be looking at to make that decision.
22 How much capacity we should retire.
23 What capacity we should retire. And what we
24 should replace it with. The logical alternative
25 would seem to be given that most of these older

1 plants, if left in service, will basically become
2 peaking units, is simply to replace these plants
3 with gas turbines with LM6000s that have roughly
4 the same heat rate as older steam turbines, but
5 operate much more efficiently, that can ramp up
6 and ramp down much more quickly and respond to
7 prices much more quickly.
8 So, we realize that the assumption that
9 nothing is going to be retired is a contentious
10 one. And we want to acknowledge that our
11 simulations might be more plausible, if not
12 dramatically different, if we retire some aging
13 capacity. And we'd like some input as to how much
14 of that should be retired and what it should be
15 replaced with.
16 And finally, if you've read our document
17 from the 13th you've seen that we proposed a
18 number of scenarios. Many, if not all, of these
19 feed into other work that the Commission is doing.
20 All, to some extent, allow us to assess the
21 sensitivity of market conditions and such indices
22 as reliability and price to the underlying
23 assumptions that we made.
24 The first scenario is that we don't
25 build Otay Mesa; we don't build Santan. A large

1 share of these plants do not come online. The
2 economy booms. We find ourselves in the middle
3 of, at the peak of the business cycle in 2006 or
4 2007 and it doesn't rain. This seems to be a
5 scenario which would test the ability of the
6 system to deal with adverse conditions three
7 years, four years down the road, under what is not
8 really worst case scenario, but a very plausible
9 one.
10 We'd like to look at high and low
11 natural gas prices. We want to test the affect of
12 these high and low prices to bound the financial
13 risk that we face. To be honest, high gas prices
14 and low gas prices are not really going to affect
15 how individual plants function on a daily basis.
16 They will affect how much renewable capacity is
17 added in all probability. The higher gas prices
18 get, the more likely we are to see renewable
19 capacity, the more likely we are to see RPS
20 targets not only met, but exceeded.
21 But more importantly, these numbers are
22 important to us because they indicate how much
23 financial risk we're at. The major risk
24 California faces right now, given that we have a
25 capacity surplus, albeit only a small one, and

1 albeit only temporarily, is financial.
2 Right now gas prices are sitting at
3 Henry Hunt at $19, the southern California border
4 they're sitting at 9, this has implications for
5 the cost of electricity and the money that comes
6 out of ratepayers' pockets.
7 We want to look at adverse hydro
8 conditions in a booming economy in 2007, '10 and
9 '13. Hopefully this will, to some extent, address
10 Mr. Arthur's concerns, that if you build out to a
11 1998 or 1999 level you're still at risk of -- you
12 still face a substantial amount of reliability
13 risk, an unacceptable amount of reliability risk.
14 We also want to look at reduced
15 renewable capacity over the 2007 to 2013
16 timeframe. Let us assume for whatever reason we
17 don't realize the amount of renewable capacity
18 that would allow us to meet RPS targets, what
19 would be the implications of that. Mostly
20 negative for prices for the environment, et
21 cetera, et cetera.
22 Finally, we want to look at a case where
23 there's a substantial amount of investment in
24 efficiency and/or conservation and/or an increase
25 in the amount of cogeneration where people

1 basically go off the system, and increased amount
2 of self generation, and increased amount of
3 distributed generation.
4 With slower load growth we have -- we
5 reap several benefits and we'd like to be able to
6 quantify that.
7 So, those are the scenarios. We are
8 welcome to doing more of them. Keep in mind that
9 we're under kind of a time constraint as
10 Commissioner Boyd has so graciously acknowledged.
11 And I think the next slide is black.
12 Oh, all these questions.
13 MS. JONES: Before we go on to the
14 questions, in terms of the scenarios, have you
15 thought about doing a faster load growth and
16 looking at more self gen, distributed gen and
17 increased efficiency as another scenario?
18 MR. VIDAVER: No. The combination of
19 those two would leave you right back where you
20 started, I think. If the economy boomed and all
21 of a sudden industry started locating in
22 California at a more rapid rate than expected, and
23 then you offset that with people putting PV on
24 their roofs and industrial concerns going offline,
25 you'd sort of end up with a baseline.

1 In choosing the variables to look at we
2 wanted to look at things that reinforced each
3 other rather than offset each other. And at the
4 same time we wanted to looked at a limited number
5 of things so we didn't drive the implicit
6 probability of the scenario down to zero.
7 We didn't want to look at, for example,
8 a faster load growth, adverse hydro conditions,
9 and two or three other variables, all of which
10 serve to stress the system when the probability of
11 all those things occurring simultaneously if you
12 were -- so, I'm sorry. I've had too much coffee.
13 MS. JONES: Yeah, I just think that
14 implies some judgments there that might not
15 reflect reality. I mean, I can envision a
16 scenario where self generation and increased DG
17 are very good ways and very cost effective ways to
18 meet high demand growth, so.
19 MR. VIDAVER: Yes, and I fully agree.
20 The first variable that you mentioned was faster
21 load growth. So faster load growth, for
22 macroeconomic or demographic reasons, would result
23 in high load growth.
24 And then if you took that off the system
25 by saying you encourage efficiency and distributed

1 generation, et cetera, you would get the load
2 growth sort of back to where it was in the
3 baseline. And that's something that we want to
4 avoid.
5 MS. JONES: I still don't understand
6 that line of reasoning, but --
7 MR. VIDAVER: Sorry, I may have misheard
8 you, I'm sorry, Melissa.
9 We have panelists, and here he is.
10 (Laughter.)
11 MR. MELDGIN: Thanks for letting me
12 know.
13 MR. VIDAVER: Mark Meldgin of PG&E was
14 gracious enough to agree to comment extensively on
15 this, but I don't think we have -- perhaps it can
16 wait until after lunch or something. But any
17 questions --
18 MR. MELDGIN: That's what I was going to
19 ask. I want to bring up something that is going
20 to take a fair amount of time. But, on the agenda
21 I see scenario considerations for risk studies
22 starting up after lunch. If that's correct, if
23 you're going to be here after lunch, I'll put it
24 on hold.
25 MR. VIDAVER: That is up to Commissioner

1 Boyd.

2 PRESIDING MEMBER BOYD: Yeah, I think

3 we'll break now. You might want to put your

4 questions up there for people to see and think

5 about as they're eating lunch. But after lunch we

6 have some questions to consider, and this

7 presentation. But if everybody's picked up your

8 presentation in the back on the table in the

9 entry, why they have your questions hopefully.

10 So we'll come back here at 1:30

11 promptly, please. It's going to be a long day.

12 (Whereupon, at 12:25 p.m., the workshop

13 was adjourned, to reconvene at 1:30

14 p.m., this same day.)

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1 AFTERNOON SESSION

2 1:30 p.m.

3 PRESIDING MEMBER BOYD: Get the train

4 back on the track. David, we left you leaving the

5 audience with questions. And also we had people

6 to make comments. So, let's pick up where we left

7 off.

8 MR. VIDAVER: We left off with Mark

9 Meldgin standing at the podium.

10 PRESIDING MEMBER BOYD: Right.

11 MR. VIDAVER: I don't know if he wanted

12 to -- do you have all your questions successfully

13 answered offline?

14 (Parties speaking simultaneously.)

15 MR. VIDAVER: We invited members of the

16 energy community to sit on a panel. As you know,

17 this is one of several reports and there are

18 separate panels for each report.

19 For whatever reason, and I hesitate to

20 dwell on it for too long, we didn't really get

21 much of a response, other than Mark. But we don't

22 really want to sit him up there ala William

23 Buckley and have him pontificate. But he is an

24 incredibly bright guy with a lot of observations;

25 and he's done modeling for years. So, he can

1 either say his piece now or wait; it's his call.
2 PRESIDING MEMBER BOYD: Well, he was on
3 his way; let's let him finish the trip.
4 MR. MELDGIN: Well, I wanted to get to a
5 question that came up briefly, and it's maybe a
6 second-order question, but it's the question of
7 whether to build transmission lines or to build
8 gas pipes.
9 You mentioned that there's the option of
10 putting the gas-fired power plant near the gas
11 supply basin or the LNG terminal or whatever, and
12 then bringing wires to bring the power to the load
13 center. Or build a gas pipe and putting the power
14 plant near the load center.
15 There's maybe four important aspects of
16 that question, at least four. One is which
17 overall is cheaper; which is more reliable in
18 terms of serving the electric demand; which is
19 more secure for the issues that the Commissioners
20 raised earlier today; and which is likely to
21 happen in the absence of any strong attempt to
22 change things.
23 So I was just wondering where the staff
24 stands on those things, those issues.
25 MR. VIDAVER: Where the staff stands.

1 Okay, that makes it a little easier. A person who
2 is more qualified than I am to answer these
3 questions, or certainly whose input I would like
4 is Bill Wood on these issues.
5 I think that it's generally acceded
6 right now that it's cheaper to build the gas
7 pipeline. I mean I don't think that Bill -- he's
8 not standing up and screaming but that's because
9 he's not here.
10 I would defer to Commissioner Boyd
11 regarding security. I don't know whether it's
12 easier to blow up a gas pipeline or a 500 kV. I
13 don't --
14 PRESIDING MEMBER BOYD: I don't want to
15 answer that question in public.
16 (Laughter.)
17 MR. VIDAVER: What is more likely? I
18 think we can all generally agree that building
19 pipe is certainly more likely. It has a much
20 shorter lag time, lead time, whatever is
21 appropriate. It's just much easier to do.
22 The regulatory jurisdiction, the
23 jurisdictional issues have more or less been
24 resolved, I believe. So, and reliability, well,
25 yeah, gas pipelines don't tend to be derated with

1 the frequency that transmission lines do. So
2 that's my answer.
3 MR. MELDGIN: I'm real surprised by one
4 of those, which is which is more likely to happen.
5 Because if it's any kind of a merchant developer
6 looking at least cost, there's some chance that
7 he'll have to pay for gas transmission on the
8 basis of some sort of charge per mile; whereas, on
9 the electric side there's a chance that society,
10 as a whole, will bear all of the costs of the
11 transmission upgrades, and possibly even some of
12 the losses.
13 MR. VIDAVER: I misunderstood your
14 question. I was answer the question which is
15 easier to site.
16 MR. MELDGIN: Oh, okay.
17 MR. VIDAVER: Now, you're answering a
18 different question, and I have no doubt that
19 you're right. Simply --
20 MR. MELDGIN: I have doubts that I'm
21 right.
22 MR. VIDAVER: -- because you're you --
23 (Laughter.)
24 MR. MELDGIN: All right, that was all I
25 had, thanks very much.

1 MR. VIDAVER: Thank you.

2 MS. JONES: Well, I think one of the

3 important issues associated with that is rather

4 than shooting from the hip, to actually look at

5 the different costs associated with all of the

6 different options and try to compare them on as

7 comparable a basis as possible.

8 MR. PRUSNEK: Hi, my name is Brian

9 Prusnek from the California Public Utility

10 Commission. And I just had a question. I was

11 wondering when we say build more gas pipelines for

12 power generation, are you referring to building

13 interstate pipelines, or increasing the amount

14 that we have instate?

15 I was kind of missing the point because

16 I didn't think there was a direct, you could

17 compare building wires versus building pipes. I

18 didn't see that as an easy choice. Maybe if you

19 could expand on that?

20 MR. MELDGIN: Well, this actually brings

21 up a comment I maybe should have made about the

22 reserve margin approach you're using. An

23 alternative scenario would be that generators

24 decide to build where gas is the cheapest. And

25 based on what little I know about gas markets and

so on, that would probably be southern California, because there's the cheap Rocky Mountain's gas coming down via the Kern River pipe. There's the potential for one or several LNG terminals in Baja.

So, one possible alternative scenario would be assume the same total number of megawatts get built, but assume that the bulk of it happens down near the lower Colorado River; and then the transmission has to be expanded to get the power into northern California, rather than assuming that the new growth is distributed nicely and evenly around.

MR. VIDAVER: Yeah, I believe, perhaps with a lack of clarity, I did say that the geographic distribution of power plants, even if they sort of met this reserve margin criteria, the total amount of capacity in aggregate was the same. It might be distributed geographically much differently.

You're pointing out that it's liable to be near an LNG terminal in Baja, for example, or on Kern River or someplace where gas is very cheap. That's a -- we'll certainly talk that over with Bill Wood and Jairam Gopal. And I have no

1 doubt that they'll encourage us to develop that
2 scenario.
3 MR. MELDGIN: Okay. And then getting
4 back to the question for the gentleman from the
5 PUC, then that's really the issue. It's, you
6 know, I don't care whether it's interstate or
7 intrastate, but if these plants get built near the
8 Bay Area, then it's the possibility that the pipe
9 will have to be expanded to get the gas there.
10 You don't need to do that if you build
11 all these power plants down in the lower Colorado
12 River. But then you probably have to expand Path
13 15 and maybe some other stuff.
14 MR. VIDAVER: Thank you, Mark.
15 Is that it?
16 PRESIDING MEMBER BOYD: What's the term?
17 Least cost best fit?
18 MR. VIDAVER: That's the term. And I
19 think there are 42 definitions of that in
20 Webster's Third International.
21 MR. ABELSON: Is it appropriate now to
22 make some comments about some of the specific
23 assumptions?
24 MR. VIDAVER: Certainly.
25 DR. ARTHUR: Well, one, on the transfer

capability between the northwest at NP15 I think you had a number that is probably correct as it relates to the nameplate, but I think it's high relative to what is typically available on any given day. So that might be something where talking to the ISO would be helpful.

But my recollection, not being a transmission planner, is that 4200, 4000 is a closer number that's typically available.

A question I didn't understand from the material presented was in the supply numbers that you provided, does that include an allowance for forced outages, or is that essentially nameplate?

MR. VIDAVER: Neither. It doesn't include forced outages, but it's derated, for example, for high ambient air temperature during the summer --

DR. ARTHUR: Okay.

MR. VIDAVER: -- if it's located inland, et cetera. So, it's sort of dependable, but doesn't include a derate for forced outages.

DR. ARTHUR: Okay. And along that line, one possible thing to consider when you're dealing with the aging of the plants is simply to change the forced outage rate which may give you a way of

1 indirectly adjusting for that possibility.
2 MR. VIDAVER: That's an excellent idea.
3 Although if we make the forced outage rates any
4 higher on some of these older plants, we'll
5 effectively be retiring them.
6 Okay, that's a great suggestion.
7 DR. ARTHUR: Well, from a modeling point
8 of view it may just a way to backdoor, where it
9 doesn't require horrendous outboard efforts.
10 MR. VIDAVER: Yeah, a heroic sets of
11 assumptions. That's a very good idea. We
12 contemplated the increasing of forced outage rate
13 uniformly on some units to deal with the notion of
14 capacity withholding at one point.
15 DR. ARTHUR: Another question I had was
16 in the aggregation of the megawatts of capacity
17 did that assume that some of the renewables are
18 100 percent available during those peak periods,
19 or did you adjust for --
20 MR. VIDAVER: Wind is given -- we've had
21 internal debates about whether the value of wind
22 was zero, 5 percent or 10 percent.
23 DR. ARTHUR: Okay.
24 MR. VIDAVER: The answers to that
25 question are sort of as much political as they are

engineering --

DR. ARTHUR: Right, and I would prefer to stay away from that.

MR. VIDAVER: Yeah, so would we. But geothermal and bio --

DR. ARTHUR: And then I would lastly like to introduce a concept that I thought about over lunch to decide how it was most appropriately introduced, and I've come up with the term friction out of the concept of physics to discuss the idea that what we've presented to this point, I think, is without friction.

And I think there are such things as regulatory friction and institutional friction that when you allow for those results in the actual reality being usually less robust than what the raw numbers might suggest, so as we progress it seems like we ought to have some sort of friction coefficient that would allow for those kinds of impediments that seem to evolve over the course of time.

And lastly, I just wanted to commend the good work. I mean, I have been slightly critical and I apologize for that, but the work is very helpful to small utilities like Redding, having

1 this quality of work and this kind of data
2 available for our own internal understandings is
3 invaluable, because we would never be in a
4 position where we could put something like this
5 together, ourselves. And we're very appreciative
6 of the work that's being done and the opportunity
7 to participate.
8 PRESIDING MEMBER BOYD: Thank you. I
9 think least cost best fit just got modified by
10 after clearing lots of hurdles.
11 MR. VIDAVER: Anyone else? Anyone in
12 this room feel free to -- Mr. Miller. I wasn't
13 serious.
14 (Laughter.)
15 MR. MILLER: Well, let me ask about a
16 process here, in that were you going to call
17 panelists up or --
18 MR. VIDAVER: To be honest, I was under
19 the impression that Mark was the only person who
20 had agreed to sit on a panel. That we had
21 solicited other entities who shall remain
22 nameless, and not received a response.
23 And Mark was the only person who did.
24 So my proposal was just to, if you have extensive
25 comments, feel free to stand uncomfortably at the

1 podium and make them.
2 But if you'd prefer to constitute a
3 panel of one or two or --
4 MR. MILLER: Well, what we have is
5 actually a team from PG&E that has, for different
6 parts of the report, I mean the transmission or
7 gas infrastructure, as well as when you go on to
8 the cost competitiveness of the generation.
9 So I'm not sure what the timing is for
10 that.
11 MR. VIDAVER: I'm not running this show.
12 Al, do you have any suggestions about how we
13 should handle this?
14 MR. MILLER: Myself, I had comments on
15 this last.
16 MR. VIDAVER: Perhaps --
17 PRESIDING MEMBER BOYD: I was going to
18 say perhaps, unless your presentation fits
19 together -- better together as one piece, it might
20 be better just to give your comments now on what
21 we've spent all morning on. And then get the gas
22 presentation and have your gas person, or whatever
23 combination, two or three folks you might want.
24 MR. ALVARADO: We are going to have
25 presentations by Judy Grau and Mark DiGiovanna.

1 They're going to talk about transmission and gas
2 issues, too.
3 So, if you prefer to wait after each of
4 the speakers, or --
5 UNIDENTIFIED SPEAKER: (inaudible).
6 PRESIDING MEMBER BOYD: Well, let's do
7 it that way. Let's go with the generation because
8 it will be too long an interval between things.
9 And so, if you've got comments now, go for it. Or
10 you and your team. Or, you're the team.
11 MR. MILLER: Bear with me here.
12 MR. VIDAVER: That is only one sheet of
13 paper, right? Okay.
14 MR. MILLER: First of all I want to, you
15 know, thank you for the opportunity to share my
16 thoughts on this. And in particular, thanks to
17 David Vidaver who helped walk me through a lot of
18 the approach, the methodology that they're using
19 for their studies.
20 And overall, you know, the assumptions
21 across the scenarios, I think provide a reasonable
22 framework for the current trends of supply and
23 demand. And I think the CEC has done a very good
24 job of identifying the key issues that the
25 California energy industry faces going forward,

1 you know, the financial market, credit risk
2 problems, reasonableness and regulatory risks,
3 transmission pricing, the problems of the illiquid
4 market and the need for developing a new market
5 structure and planning processes which come along
6 with the reserve requirement, and price cap issues
7 and all those things.
8 So where I'm leading is if the objective
9 of this effort is to use the findings from these
10 studies, from the baseline study and the
11 scenarios, to develop policy and shape the
12 industry going forward, it's crucial to define the
13 scenarios to frame the key issues that you want to
14 bring forward.
15 So that being said, one of the big
16 concerns I have is that my belief is that the
17 industry is very capital intensive. And on the
18 topic of reserve margins, in particular, using the
19 '98/99 reserve margins may have been a period
20 where reserve margins were pretty high.
21 And there's been a lot of different
22 suggestions for different reserve margins going
23 forward; anywhere from, for example, the FERC, you
24 know, 12 percent minimum; I think the PUC has a 15
25 percent; California Power Authority 17 percent.

1 So, the high reserve margins can, you
2 know, reflect an over-supply condition, you know.
3 For example, if you were to build out, you know,
4 50 percent reserve margin with combined cycles, I
5 mean that would really flatten out the volatility
6 of prices and stuff. But there's a cost for doing
7 that.
8 And so I think it's important to
9 quantify the cost of carrying this excess reserve.
10 So the point is the reserve margins requirement
11 may have a significant impact to the supply curve,
12 and ultimately to market prices.
13 So this leads right into, you know,
14 uncertainty in market prices. This is going --
15 the reason I bring that up is that same period
16 there was fairly low prices in the 98/99 period.
17 And may not have been that attractive for new
18 investments.
19 The crisis happened. A lot of
20 generation did come on, and as a result of that,
21 prices came down again in 2002 by a good margin.
22 So, --
23 CHAIRMAN KEESE: Actually, we released a
24 study -- when we released the heat storm study in
25 '99 we also released a study saying that the

1 market dynamics were not there. That if you built
2 a power plant you would lose money. And that's
3 what would have happened in '99 and 2000.
4 MR. MILLER: Right. So, you know, going
5 forward what I think needs to be captured is the
6 tradeoff between the cost of reserve margins, you
7 know, versus the market price of energy. You
8 know, you can have one choice to be to have a high
9 reserve margin and less volatility perhaps on your
10 supply curve. Or the tradeoff would be go with
11 the less cost of having a lesser reserve margin
12 and maybe more volatility on your price. But
13 there's a tradeoff there. And I think that's
14 something that we could probably, you know, maybe
15 in the scenarios, quantify.
16 In addition to the market prices that
17 are calculated, I think it's imperative that you
18 bring up the payments, the revenue, you know, the
19 capacity costs, payments for ancillary services,
20 and all those other flavors of revenues that would
21 go towards covering the fixed costs and capital
22 investments of new generation. Because, again, to
23 get the right understanding of the price of power
24 you need to do that. Okay.
25 So I have a couple suggestions for

1 scenario enhancements. One would be perhaps you
2 could put this into the high load growth and fewer
3 additions is to maybe go with the -- study the
4 impact of a lower target reserve margin of, you
5 know, whatever number it is, 12, 15 percent, in
6 comparison to -- okay.
7 MR. VIDAVER: You said to look at that
8 in the context of higher load, lower adds.
9 MR. MILLER: Right.
10 MR. VIDAVER: So that effectively would
11 be a lower reserve margin compared to the
12 baseline. And what you're suggesting is that we
13 look at the financial consequences of --
14 MR. MILLER: Yeah, the impacts to the
15 market clearing prices, et cetera.
16 MR. VIDAVER: Okay.
17 MR. MILLER: And the second scenario, I
18 think it's important -- this is what Mark was
19 leading to -- is the location of the generation, I
20 think, is a big thing.
21 And we talked about the planning
22 reserves, and maybe doing, on one side doing it on
23 a service territory basis, building out to meet
24 the reserve requirements versus on a statewide
25 basis or a broader regional basis, and have, for

1 example, the siting of generations closer to the
2 interstate gas pipelines or wherever and --
3 MR. VIDAVER: As Mark suggested.
4 MR. MILLER: And then, again, you know,
5 those costs of the different scenarios should be
6 rolled forward in the analysis to see what is the
7 least cost most benefit.
8 Another point or suggestion is maybe,
9 you know, from analyzing the viability of the new
10 generations, or the generations on the margins,
11 setting the prices is to sort of use a balance or
12 income statement approach where, you know, you
13 determine the cost effectiveness of the resources
14 by looking at the revenue streams from the market
15 prices to see what costs they are recovering, and
16 if they're recovering a reasonable rate of return.
17 MR. VIDAVER: What would be the goal of
18 looking at that? The difference between what they
19 need to recover in the energy market --
20 MR. MILLER: Well, it can be useful in
21 numerous ways. One, it can, you know, on the long
22 term if, for example, on the 2007 through '13, if
23 you're trying to mimic a market in an equilibrium
24 you would assume at that point that -- let's say
25 for example, a combined cycle, would be making

1 their targeted rate of return, whatever that is
2 defined as.
3 I think that would be -- you'd want to
4 see the capacity factor and those things realized,
5 as well, from new generation.
6 On the other hand, you know, from the
7 retirement units it could be useful and
8 instructive to adjust their costs of operating.
9 Maybe they discount, you know, maybe they don't
10 have the capital costs, maybe they're already, you
11 know, they could go forward just on operating
12 costs or ongoing forward costs and could discount
13 and maybe become more competitive or extend their
14 competitiveness.
15 MR. VIDAVER: Yeah. One of the problems
16 with the latter is that we do not have access to
17 the information that allows us to adequately or
18 accurately assess going forward costs for existing
19 facilities.
20 So, that's something we might have been
21 able to weasel out of you ten years ago, but we
22 certainly can't get it out of Mirant and Reliance,
23 so.
24 MR. MILLER: I realize that's -- you
25 could make some, for example, you know, the fixed

costs. You know, you could maybe make an assumption.

MR. VIDAVER: Can we come to you for some best guesses as to what those going forward costs might be?

MR. MILLER: Perhaps we could discuss it.

MR. VIDAVER: You can take your guesses as to what X Edison facilities would be --

MR. MILLER: I understand. It would be, you know, controversial, but could be instructive to see --

MR. VIDAVER: Yeah, agreed.

MR. MILLER: -- to see the results. Okay. And the last comment I would like to make is, and actually this goes back to yesterday, and this is one we had a discussion on, on electric rates.

And it was a pretty good discussion going on, and a lot of, you know, controversy on being able to forecast those going forward. And I thought that this effort with the scenarios, I thought it would be extremely useful if you could roll forward the impacts of each scenario into a rate guesstimate.

1 I think it would be very -- in other
2 words, take a value chain approach. See the
3 impacts to the costs of the transmission systems;
4 see the cost impacts to the wholesale power; or
5 renewables, supporting the renewables mandate.
6 All those things.
7 And if you could look across that
8 spectrum I think it would be very instructive for
9 making policy decisions, perhaps. So, that's it.
10 MR. VIDAVER: Thank you very much. One
11 observation about a very small point, yet
12 significant point. You said look at the income
13 streams from the energy markets in assessing the
14 viability of new combined cycles.
15 I mentioned that we look at the capacity
16 factors of new combined cycles, and we want to
17 drive them high enough when they reach a certain
18 point that we decide it's time to start adding
19 peaking units.
20 When we get combined cycles up to, you
21 know, 80 or 85 percent or whatever, sort of
22 equilibrium operating level we think that they
23 would be at, we will then, of course, check the
24 market prices and see what kind of spark-spread
25 we're looking at.

1 And heaven help us if that spark-spread
2 isn't high enough. You've run these models. You
3 know sort of the -- in some sense it's kind of an
4 art.
5 Another observation is that right now,
6 and I don't want to speak for our engineering
7 office, but estimates as to the cost of, the
8 incremental cost of transmission upgrades, when
9 you move from scenario to scenario, are not
10 readily available to us.
11 Now, we may have that capability and I
12 may not be aware of it. Again, we may come back
13 to you and ask you for your input in that regard.
14 The two scenarios that -- a third
15 comment is that we also have a difficult time, we
16 have to make a lot of assumptions when it comes to
17 non market sources, or non energy market sources
18 of revenue. Most people, when looking at these
19 problems, make some very generic assumptions about
20 ancillary service revenue will be 5 percent of
21 energy revenue, or something like this.
22 So, looking at the financial
23 consequences as you move from a baseline into a
24 scenario is a little bit difficult. We certainly
25 don't question the value of doing that. In fact,

that, from a social perspective, that's probably the most important thing we can be doing, looking at all the costs associated with different choices regarding reserve margins and reliability in trying to assess what kind of bang you get for your buck.

You, of course, will be the first person to acknowledge that coming up with numbers related to those different scenarios might involve a lot of rather heroic assumptions. So, assuming we do move forward as you suggest, we ask for your forbearance when we roll out the final results, and say that we made certain assumptions about ancillary service revenues, et cetera, et cetera.

So thank you very much for the suggestions. They will be taken to heart.

So, any more modeling geeks out there?

MR. SMITH: My name's Don Smith from the Office of Ratepayer Advocates, and I have two comments.

You said a few minutes ago that there's no mathematical way to determine the firm capacity for wind, and I disagree. It's the effective load carrying capability. And it's been done for the various windfarm areas in California including

1 several studies by me when I was working for PG&E.
2 And it's approximately 25 percent of the rating,
3 not the much lower numbers you were giving.
4 My second comment is it's kind of
5 misleading to speak in terms of reserve margin in
6 that we really want a system reliability; want to
7 measure probably in a loss load probability
8 number. And you can have the same reserve margin
9 and one system will be much more reliable than the
10 other, or less, depending on the relative -- well,
11 the absolute reliability of all the units, all the
12 power plants, and the relative size, particularly
13 at the largest plants in the system.
14 If you have one huge plant, say,
15 supplying 20 percent of your peak load, and if you
16 had a 19 percent reserve margin that would
17 definitely not be good enough, because that one
18 plant going down, and you have a loss of load.
19 So, those are my comments.
20 MR. VIDAVER: Regarding the second
21 comment, we understand that the reserve margin
22 alone doesn't tell you about the reliability of
23 the system. The forced outage rates, unit sizes,
24 et cetera, all impact this.
25 At this point we're unwilling to go

1 forward with the models that we have, and use the
2 LOLP output to sort of search for the set of
3 resource additions that yields a one-day-in-ten-
4 year LOLP, for example. That's a very time-
5 consuming kind of iterative process where you try
6 and get to that number while, at the same time,
7 you don't necessarily have great confidence in the
8 ability of the model you're using to generate that
9 number accurately.
10 We're long past ELFIN and one utility
11 and a very simple step function for imports.
12 These models are black boxes whose output can't be
13 taken necessarily without several grains of salt.
14 One of the concerns that we have is when
15 we look at LOLP numbers out of the models that we
16 use, they tend to be really low. They tend to be,
17 you get down to reserve margins below 10 percent
18 before your LOLP starts to get to a level that
19 calls reliability into question.
20 So, I don't want to go so far as to say
21 as though there's something wrong with the model,
22 but again, it has to be taken -- the results have
23 to be taken with several grains of salt.
24 The other observation I would make on
25 this particular topic is that there's a political

1 element involved. And even if the model could
2 prove to us beyond a shadow of a doubt that a 9
3 percent reserve margin yielded an adequate amount
4 of reliability it would be very hard to sell.
5 These models also make a number of other
6 assumptions, including the participation of
7 generators with an absence of withholding, et
8 cetera, et cetera.
9 So if a model is giving you an adequate
10 LOLP at a 9 or 10 or 12 or 11 percent reserve
11 margin, you sort of have to call it into question.
12 But your point is well taken. The reserve
13 margins, while they tell you something, they don't
14 tell you everything.
15 Regarding the load carrying capability
16 of wind, I will admit to not having read the
17 studies you participated in. And I am amenable to
18 doing so. However, at the time of the system peak
19 in southern California during the past several
20 years, Mark Minick could probably give me the
21 exact number, but I think you have 1200 megawatts
22 of -- you, we have 1200 megawatts of wind capacity
23 in southern California.
24 And at the time of the system peak over
25 the past several years, the amount of energy

that's been generated by those units has been barely in double digits. We're talking like 20 megawatts out of 1200 megawatts of capacity have been generated on system peak.

And while there may be a methodology which validates a contribution of wind of 25 percent to a resource accounting process, let's just say you could possibly convince me of this. I don't want to say that wind doesn't have value in the system at all. The Commission has taken really strong stands on the value of renewable generation, including wind, and supports it; and will continue to do so.

But, from a planning perspective certain realities have to be taken into account, and this being one of them. Now, if there's a way to circumvent this, I'm all for it. But, again, this is a modeling exercise. This is not a policy proposal or anything like that.

MR. MINICK: Mark Minick from Southern California Edison. I'm trying to sit back there quietly and absorb what's going on, but since you are talking about wind, possibly in our service territory, we have done some studies. And I appreciate that you've done some studies in the

1 past.

2 From a modeling perspective I'm

3 comfortable with what David's doing. I would have

4 difficulty saying that wind, at the time of the

5 system peak, either ISO's peak or Edison's peak,

6 can carry more than about 10 percent maximum in

7 dependable operating capacity for the purposes of

8 reliability. And the energy, likewise, is going

9 up. And I appreciate that.

10 As far as LOLP calculations, we're

11 trying to do them. And I accept David's

12 explanation that it's somewhat difficult. What we

13 did in one case, David, was the model seems to

14 think you don't interrupt firm load until you get

15 to zero percent reserves. So push it up three

16 because the ISO will probably start interrupting

17 load at 3 percent. So that'll push your 10 to 13;

18 it helps a little.

19 MR. VIDAVER: Thank you. Everybody's

20 looking at me like I'm supposed to talk. I think

21 one of --

22 CHAIRMAN KEESE: I would --

23 MR. VIDAVER: -- supposed to talk now.

24 CHAIRMAN KEESE: -- just confirm, we get

25 reports through different forums on what the

1 generation for wind is, and we have days when it's
2 been at 10 megawatts. So there are days when it
3 is, the wind is not blowing in California. And
4 generally they coincide with hot days, which are
5 system peak days.
6 MR. VIDAVER: That's why they're hot,
7 usually. No wind.
8 MR. SMITH: Implicit in what you just
9 said is that when you're thinking about system
10 reliability you're, in effect, assuming that all
11 the risk of system failure is concentrated in one
12 hour, or just a few you choose. You're assuming
13 you know ahead of time exactly what the peak load
14 is going to be in megawatts, which you don't.
15 There's a probablistic distribution there.
16 And you're assuming that the
17 dispatchable plants have absolute reliability.
18 That's not true, either, because you get a
19 probablistic distribution again when you look at
20 what you can really get at any given time from
21 your system.
22 So I think, because all of those three
23 things are not correct, that you're dealing in a
24 more probablistic situation. You have to look at
25 a huge number of hours; see how wind is doing;

1 calculate system reliability with and without it.
2 And that's how you can find the effective load
3 carrying capability.
4 And I've been having this feud with SCE
5 in some of the proceedings, and I'm sure it will
6 continue. That's my opinion.
7 MR. VIDAVER: There's one point of
8 clarification, and that is that the models that we
9 use have a representation for thermal unit
10 outages, meaning that there is a draw in every
11 hour as to how much capacity is going to be
12 sidelined due to unanticipated maintenance needs.
13 So that in a representative hour, peak
14 or otherwise, about 6 percent of your system
15 thermal capacity is not going to be available.
16 And in some draws that number can approach 10
17 percent.
18 So I don't think we're assuming that all
19 thermal capacity is going to be available in the
20 peak hour or any other hour, for that matter. But
21 I don't want to get into the middle of a feud
22 between you and Edison, so --
23 (Laughter.)
24 MR. VIDAVER: Sorry.
25 PRESIDING MEMBER BOYD: Anyone else in

1 the audience have a comment? I think you're
2 retired, David.
3 MR. VIDAVER: Thank you. Is that a
4 polite way of saying that -- no, okay.
5 (Laughter.)
6 PRESIDING MEMBER BOYD: Time's up.
7 MR. VIDAVER: Cold standby. Okay, thank
8 you.
9 PRESIDING MEMBER BOYD: Thank you, that
10 was a long day for you, David.
11 Al, do you want to introduce the next
12 subject at least?
13 MR. VIDAVER: Oh, yeah, I'd be happy to.
14 I think she would like to know how to --
15 PRESIDING MEMBER BOYD: He responds to
16 Al, too.
17 MR. VIDAVER: Both of us would like to
18 know how we get this -- I'll let Al do it.
19 (Pause.)
20 MS. GRAU: All right, our technical
21 difficulties have been solved. I'm Judy Grau with
22 the transmission evaluation program. And before I
23 get into my presentation I just wanted to note a
24 few things.
25 First of all, I'd like to thank the

1 staff members who assisted in writing chapter
2 three, which is the electricity transmission
3 infrastructure chapter. And that's Don Kondoleon,
4 Mark Hesters and Clair Laufenberg.
5 The other thing I'd like to note is that
6 if you picked up a copy of the infrastructure
7 report you should have an errata page inserted in
8 there. It goes with appendix B, table B-7. And
9 so if you do not have that insert, I think we have
10 extra copies in the back. I can get you one after
11 my presentation.
12 And the other thing is Gary DeShazo of
13 the California ISO will also be making a formal
14 presentation, PowerPoint presentation, right after
15 mine on the ISO's comprehensive transmission
16 planning process.
17 And so what I'd like to do, in the
18 interest of time, is to do my presentation; have
19 Gary do his; and then have the panel approach.
20 Because some of your questions may be best
21 answered by one of the utilities or the ISO. And
22 so we have several folks who have volunteered to
23 be on a panel, and it might be easiest to save all
24 your questions when the right person is already up
25 at a microphone and can answer.

1 So, if that's okay, unless you're
2 absolutely dying, we'd like to try and hold the
3 questions.
4 Okay, the topics I'm going to cover
5 pretty much follow the outline of the chapter
6 three. So if you've read chapter three, this
7 should all look familiar to you.
8 First we're going to talk about the
9 major transmission projects modeled, and you'll
10 see some references to what Dave Vidaver talked
11 about this morning in terms of the transmission
12 topology and what assumptions we're making.
13 And then talk about local reliability
14 projects, some economic projects, transmission to
15 support renewables, and then finally the out-of-
16 state projects.
17 And so there are seven projects that
18 I'll be talking about here that fit in with our
19 transmission topology. So let me turn to that
20 slide to point out where these projects are.
21 The first one from north of Path 15 to
22 San Francisco would be the Jefferson-Martin
23 project upgrade which we'll be talking about; I'll
24 talk about it in the next slides. I just want to
25 point them out, where they are on this figure,

because they're not marked.

From Zonal Path 26 to north of Path 15 is the Path 15 upgrade. From SCE to Zonal Path 26, this is Midway-Vincent, a short-term upgrade. And I'll talk about short term versus long term.

From SCE to SDG&E, this is the path that would include the Valley-Rainbow upgrade assumption. From SDG&E to Miguel is the Miguel-Mission upgrade. And from SCE to IID is part of the Path 46 west-of-river upgrade we'll be talking about.

And the final one s a Path 45 upgrade. Path 45, at least on this topology is both of these paths, Tijuana-Miguel and LaRosita to Imperial Valley.

And I'll be talking about these in the order in which we are modeling them to become available. So the first one is the Path 45 upgrade. And this, as I noted, -- oh, sorry, don't have the picture up anymore -- but this is from LaRosita to Imperial Valley. That reconductoring of the 230 kV line was already completed. It was completed in November 2001. And increases the transfer capability.

However, the current status is that the

1 WECC has not yet approved from south to north the
2 summer rating increase to 800 megawatts. So staff
3 is going to model it 800 megawatts bidirectional
4 because we expect that WECC approval very soon.
5 The next upgrade is a short-term upgrade
6 from Midway to Vincent. And this is primarily an
7 operating procedure change. I think it involves
8 some remedial action scheme work and such. This
9 is considered an economic project, not a
10 reliability project, as some of the others are.
11 It is under construction at the moment,
12 and if you look in our tracking sheets at the
13 back, Southern California Edison has a predicted
14 online date of June of 2003. But staff has heard
15 in another venue that PG&E has a slightly later
16 date of September 2003. So if you have any
17 questions maybe when we get the utility
18 representatives up for the panel, they can talk
19 about why there's a discrepancy.
20 And from a modeling perspective then,
21 this increases the transfer capability
22 bidirectional from 3000 to 3400 megawatts. And
23 we're assuming the later date, so we're using
24 October 2003.
25 The next upgrade is the Path 15, Los

1 Banos to Gates. This is also an economic project.
2 The project is being sponsored by Western Area
3 Power Administration, Trans-Elect and PG&E. And
4 we do have Morteza Sabet of WAPA here, and he can
5 talk more about the project also again when we
6 open it up to the questions for the panel.
7 And this increases -- we have the
8 modeling assumption that this increases the
9 ratings as shown, and we're using January 2005 as
10 the effective date for that.
11 Next project is Miguel-Million in the
12 San Diego area. And this, again, is another
13 economic project. Current status is, for those of
14 you who have been following the proceeding, no
15 CPCN is needed for the Imperial Valley upgrades,
16 but there will be CPCN needed for the Mission-
17 Miguel line. But the PUC has agreed to expedite
18 that and take the record that's already been
19 developed.
20 So our modeling assumption is that that
21 will occur and increase the transfer capability
22 into the downtown San Diego area as of January
23 2005.
24 Next upgrade is the Jefferson to Martin
25 in PG&E's territory. This is a new 230 kV line.

1 It needs a CPCN. And that was filed at the PUC on
2 September 30th. And there's a prehearing
3 conference January 10th. We are assuming that
4 that will become available as of January 2006.
5 All of these projects, by the way, can
6 be found in the appendices. Appendix table B-1
7 through B-7 are the seven planning areas for PG&E.
8 Table B-8 is for San Diego. And table B-9 is for
9 Southern California Edison. So these are all in
10 there.
11 The next project involves Path 46, west
12 of the river, and I think Dave talked about this
13 this morning, that this one is not an actual
14 project being proposed or sponsored by anyone at
15 the moment. But it's just the conceptual idea
16 that with all of the -- to meet the renewable
17 portfolio standard we may need -- that may be met,
18 I should say, by geothermal development in the
19 Salton Sea area.
20 And to get all that generation out
21 there's going to probably have to be some sort of
22 transmission upgrade. And so for purposes of our
23 baseline assumptions, we're assuming an increase
24 from the IID to SCE interconnection of 1000
25 megawatts in January 2009.

1 And then finally, or maybe not so
2 finally, yeah, this is the last one of the major
3 projects, is the Rainbow-Valley project. This
4 would be a new 500 kV line from the existing
5 Southern California Edison Valley substation to a
6 new San Diego Gas and Electric Rainbow substation
7 and then some other ancillary lines are also part
8 of that upgrade.
9 This is considered by San Diego to be a
10 reliability project. Many of you know that they
11 filed for a CPCN and it was denied by the PUC, I
12 think in December 2002 as being not needed for
13 reliability until at least 2008. And the current
14 status is that SDG&E has filed for a rehearing.
15 And as far as we know, no action has been taken
16 yet.
17 For purposes of our modeling we are
18 assuming an inservice date of January 2009. And,
19 again, as Dave has said, and as some of you know
20 if you've followed the case, this all hinges -- it
21 hinges quite a bit, the argument, on whether Otay
22 Mesa comes online in the local area in 2005 or
23 not. And because San Diego is a local reliability
24 area, the baseline assumption is that something
25 will be built to meet need by December 2005,

1 whether it's Otay or Palomar or something else.
2 And so we obviously will be looking at
3 alternative scenarios that don't include Otay Mesa
4 or other local additions, but just confirming that
5 for baseline purposes we're assuming it'll be
6 deferred until 2009.
7 Okay, moving on then to the local
8 reliability projects. These are the ones that are
9 needed to conform within Cal-ISO's planning
10 standards timeframe, within five years. I put for
11 the 2002 process, because as Gary DeShazo will be
12 talking about, the ISO has come to the conclusion
13 that a minimum five-year time planning horizon may
14 not be enough to get some of these projects
15 underway, as we saw kind of in response to the
16 Valley-Rainbow denial. So, we'll be talking more
17 about that.
18 But for now, what I have included and
19 analyzed in our chapter is based on the 2002
20 process in which the utilities responded with
21 plans that looked out just five years, within a
22 look beyond at other major projects, but for the
23 most part within five years.
24 These plans are updated annually and
25 submitted to the ISO, so it's an annual update of

1 the five-year plan, or at least it has been.
2 Current status is that the 2002 assessments have
3 been completed and we're just getting underway
4 with the 2003 assessment process.
5 And so just briefly, I have six
6 categories of utilities of projects that I'll be
7 talking about. I'm going to go through this
8 pretty fast because if you have read the chapter
9 it's all in there. And I know we have a lot to
10 talk about this afternoon.
11 Just wanted to briefly state where I got
12 the information that's in all those appendix
13 tables. And I used each of the utilities' final
14 transmission expansion plan reports. And the
15 monthly filings that the utilities make to the PUC
16 as part of their AB-970 requirement. And then
17 also the California ISO's control grid study
18 report which is available on their website.
19 And as I noted earlier, there's seven
20 planning areas in PG&E, and this is the breakdown.
21 The names of the planning areas, as well as how
22 many projects, are in the tables in the
23 appendices, that we are reporting on.
24 Same thing for San Diego. Sources of
25 information was their annual grid expansion plan,

1 plus their monthly filings. And the ISO report,
2 again. And they have 23 projects that are
3 reported on.
4 Southern California Edison, same thing.
5 I have a slide mentioning the Tehachapi project,
6 specifically. I had foresight that you'd be
7 asking about that, so I put this in here. Anyway,
8 they have completed the phase two Tehachapi
9 transmission conceptual study. A CPCN would be
10 required, and it's listed in the tracking sheet as
11 being in the planning stages for the projected
12 online of December 2006.
13 In the Imperial Irrigation District we
14 are aware of two expansion projects, two options I
15 should say. In our staff draft report we mention
16 three options, but that option, from what I
17 understand from our staff working on the siting
18 case for Blythe II, that option is no longer being
19 considered.
20 Blythe II is in our permitting process
21 right now. And there are some project changes
22 they've been making which are causing some delays
23 in schedule. But, again, as Dave said, you know,
24 we're not assigning any yea or nay to whether that
25 project will receive a permit or not. We're just

1 noting that there have been some delays.
2 And Blythe I, which Dave Vidaver also
3 had in his slides, is coming online. The expected
4 date for that is April 15th, so that will be soon.
5 And it's my understanding that the existing
6 transmission system in that area is sufficient to
7 handle the generation from Blythe I, the 520
8 megawatts from that. And this expansion project
9 noted here would be needed if, and only if, Blythe
10 II is constructed.
11 And then in the western area they have
12 an environmental impact statement done for a
13 proposed project that includes some reconductoring
14 and a new double circuit and various realignments,
15 as noted here. And this is a reliability project.
16 This area has been studied quite a bit through the
17 Sacramento area transmission -- what's the PG?
18 Planning group.
19 They've been looking at that. So my
20 understanding is that the comment period has ended
21 and the distribution of the final EIS is scheduled
22 for May 2003. However, they're still looking for
23 funding sources, but Morteza maybe could tell you
24 more about that. And right now we don't have a
25 projected inservice date, but again, maybe Morteza

1 could shed some light on that, too.
2 The City of Santa Clara Silicon Valley
3 Power, they had, I think, it's a four-mile
4 transmission line to connect from their northern
5 receiving station to PG&E's new Los Esteros
6 substation. This is included in PG&E's table for
7 PG&E. You'll see that in there.
8 The Los Esteros substation is supposed
9 to be operational in May of this year. And then
10 the line from the northern receiving station to
11 that new substation, the Santa Clara line, will
12 be, should be operational by the end of 2004, at
13 least according to their website.
14 Additional economic projects. I've
15 already mentioned some of them. Path 26, the
16 short-term solution. Path 15, and the Miguel-
17 Mission and Imperial Valley substation. And those
18 are all major projects that we are modeling in our
19 transmission market SIM program.
20 There's another Path 26 long-term
21 solution which would involve some reconductoring
22 of 500 kV lines. And this would bring the
23 capacity from -- the short-term solution brings it
24 from 3000 to 3400 transfer capability. This would
25 bring the transfer capability up to 4000

1 megawatts, bidirectional.

2 And the current status of this is that

3 it's in the planning stage, and I don't believe

4 there's an online date, but if someone from the

5 ISO or the utility would like to comment further

6 when we get to the panel part, please do so.

7 Transmission projects to support

8 renewables. I think most of you are probably

9 familiar with the renewable portfolio standard and

10 the statutes and who's doing what for that. As

11 you know the Energy Commission has to provide the

12 draft renewable forecast -- renewable generation

13 development to the PUC by July 1st. And then the

14 CPUC is charged with actually creating the

15 transmission plan.

16 And there was just a ruling from ALJ

17 Gottstein this morning, so for those of you on

18 that proceeding, watch for that when you get your

19 email. And she lays out some timelines and dates

20 for who's going to do what by when. So you can

21 read about that.

22 And that, just noting again we're

23 assuming 1000 megawatt increase from IID to SCE,

24 and that's to accommodate the renewables in the

25 Salton Sea area. And, in fact, Coral Power, LLC,

has proposed a 500 kV line from the Imperial Valley substation to the Southern California Edison Dever substation. And the January 29th ruling by ALJ Gottstein has ordered the utilities to investigate the feasibility of that.

The out-of-state projects. We are aware of the Trans-Elect and Dine Power Authority developing the Navajo Transmission project. As I've heard from Don Kondoleon, he says there is no impact on California of that upgrade unless there are other west-of-the-river upgrades made. So that doesn't -- you won't see that in our model because it doesn't affect California.

Another study group, though, in the southwest, Southwest Transmission Expansion Plan, the STEP group, they are looking at facilities to increase the transmission and transfer capability in Arizona, Nevada, Mexico and southern California. So there may be some longer term projects coming out of that effort.

And then just turning to the questions. This is the short version of the questions David had at the end of his slides. But before we get into answering those questions, I'd like to turn it over to the ISO, Gary DeShazo.

1 And then we'll open it up to the
2 panelists. And as far as I know, so far, Morteza
3 Sabet of Western, and then Gary, as well as maybe
4 Robert Sparks from the ISO, and then Chifong
5 Thomas, I understand, from PG&E might like to be
6 on the panel. And then anybody from Edison or San
7 Diego, of course, is welcome to join us, also, or
8 any other utility.
9 So, let's turn it over to Gary.
10 MR. DeSHAZO: Thanks, Judy. My wife has
11 all kinds of names for me, too, so I'm used to
12 that.
13 I'd like to just introduce myself. I am
14 Gary DeShazo; I'm Regional Transmission -- or
15 Regional Planning Manager of California ISO. And
16 I just would like to extend my appreciation to
17 those of you involved in setting up this process
18 for allowing me to take a few minutes of your time
19 to talk about the transmission planning process
20 that the ISO has in place.
21 I have been in the utility business for
22 probably a little over 24 years now. The first 23
23 years of my career -- all of that has been in
24 transmission planning, by the way -- and the first
25 23 years of my career was with the Salt River

1 project, which is about a 5400 megawatt utility;
2 and it's located in the Phoenix metropolitan area
3 in Arizona.
4 So, David, I'm very familiar with places
5 like Santan and Mesquite and all of the stuff
6 that's happening at Palo Verde and so on and so
7 forth.
8 When I made a decision to leave SRP and
9 come to work for the ISO I got two comments from
10 my peers and friends there. And one was, you
11 know, what are you thinking, you're just going
12 into the frying pan, and those folks don't even,
13 they don't know what they're doing.
14 And the other is that, you know, do you
15 even understand what change is all about.
16 Well, you know, I've been at the ISO now
17 for a little over 15 months and I guarantee you
18 that I understand what change is all about,
19 because that's what that job is about.
20 With regard to whether or not people
21 here understand what they're doing, I guess I sort
22 of look at that as someone sitting in an armchair
23 watching a football game and second-guessing what
24 a quarterback does.
25 And I will tell you that this is

1 probably the best move that I ever made, because
2 the people that I've had the opportunity to work
3 with, and I think you've seen some of that this
4 morning, are very dedicated individuals. And we
5 all recognize that we've got some difficulties and
6 problems, but we're all focused on trying to
7 figure out how to make it better and how to look
8 out for the long term needs for the state in terms
9 of our energy needs and transmission needs.
10 It's been a very interesting process
11 over the last 15 months, learning about how this
12 stuff works. But I've noticed some things that
13 have not seemed, at least, to be coming across
14 very well. And one of those is with regard to the
15 planning process that the ISO uses.
16 And so I've struggled with whether or
17 not to fit into the effort that you have going on
18 here, but I think after listening to the speakers
19 this morning and this afternoon, that, in fact, I
20 think we do very much fit into this.
21 And so what I would like to do is just,
22 I realize you're kind of short on time, and so I
23 may just sort of skip through some of these
24 things. I know there's some animation in some of
25 these slides, and we'll see where that takes us.

1 But, I would like to just spend a few minutes and
2 just maybe go over the planning process that we
3 have. And then talk about where we are heading,
4 where the ISO is heading in 2003; take us beyond
5 just the standard or traditional planning process
6 that we have been using.
7 I think the first thing that we want to
8 maybe take a look at is what's shown up here are
9 the three major what we call the PTOs, or the
10 participating transmission owners. These are
11 Southern California Edison, San Diego Gas and
12 Electric and Pacific Gas and Electric.
13 And each year the ISO enters into an
14 expansion planning process with these PTOs to
15 develop a ten-year expansion plan for their
16 system. We work with them individually. They go
17 through a process, a very stringent stakeholder
18 process, where they look at the transmission
19 requirements and facilities that are needed in
20 order for them to meet all of the reliability
21 obligations that they have.
22 As part of that process the ISO does
23 what we call a control grid study. And the
24 control grid study is an opportunity to feed the
25 information from the expansion plans into a common

1 database, so to speak, where we take a look at the
2 500 kV system, or what I called the backbone
3 system in California.
4 And the concept here is that we're
5 trying to find a way that we take these individual
6 expansion plans; and then we perform this work;
7 feed that into the control grid study; and make
8 sure that at least at the -- level, ties together.
9 Now, in addition to that there's other
10 things that are shown up here in yellow with
11 regard to processes that the ISO also goes
12 through. Most of you, obviously you probably
13 recognize the reliability must-run generation
14 studies that we do on an annual basis.
15 We also have now become responsible for
16 new generation, new generator interconnection
17 requests. And we also will do special focus
18 studies from time to time as the needs arise.
19 Well, if we look at what the control
20 grid study is, and if we just think about the fact
21 that it's the home for the overall process, then
22 the key is how does all this stuff fit together.
23 And what the control grid study does, in essence,
24 is to try to bring all of the expansion plans
25 together in concept so that you have a tie between

1 what the PTOs are doing, the overall assessment
2 and independent assessment by the ISO to look at
3 how that impacts the transmission needs, and to
4 make sure that they match up. In other words, we
5 shouldn't be finding anything in the control grid
6 study that the expansion plans haven't already
7 found. And vice versa.
8 And so it's sort of a checks-and-
9 balances thing in terms of the process. The
10 control grid study is also a stakeholder process,
11 just like the expansion planning process is. And,
12 as always, we still have these yellow circles out
13 there that are other things that we do.
14 But the key is that while they don't,
15 you know, it sort of looks like they sit out there
16 by themselves, they don't really do that.
17 What I'm trying to illustrate here is
18 that there's a stakeholder process, and I sort of
19 call this green area the world of stakeholders,
20 that's the glue that ties all of this stuff
21 together.
22 The concept is that the stakeholders are
23 participating in all these processes. And while
24 we're involved in trying to get the work done and
25 develop the needs and assess the transmission

1 facilities, the stakeholders are also there to
2 bring forward what their concerns and ideas are.
3 And they may see issues in RMR studies that may
4 have some implication with regard to how an
5 expansion plan is done, say either in PG&E or
6 Edison's area, or elsewhere.
7 And so the green area is a way that
8 allows the stakeholders to sort of traverse the
9 boundaries between all these processes that we
10 have.
11 In essence, making this work, we have
12 several pieces of this puzzle in terms of how this
13 gets facilitated. The ISO, of course, takes the
14 leadership role in doing this. We are
15 establishing the reliability and economic need of
16 transmission facilities in the state.
17 We take a longer term overall view of
18 the transmission and reliability needs. And most
19 importantly of all, our intent is to
20 collaboratively work with the PTOs and the other
21 stakeholders, as well as the state.
22 At the same time you have the PTOs, they
23 have their process where they're the ones that are
24 actually performing the technical studies to
25 develop the expansion plans. They focus on their

1 internal systems. And I think that that is where
2 many have erred in thinking that we only do five-
3 year planning studies. Okay, because they focus
4 really in depth on that five years so they get a
5 good idea of what they need so they can go do
6 their budgeting process.
7 But if you look into the expansion
8 plans, and certainly within PG&E's expansion plan,
9 which I'm mostly involved with, you'll see it goes
10 beyond that. Okay. And the intent has always
11 been to go at least out to ten years. And I think
12 that the utilities, prior to the ISO's existence,
13 were doing those kinds of things. It really did
14 not stop. But for some reason the process just
15 kind of got focused down to this five-year period.
16 So, I'm trying to stop that mode of
17 thinking; and get people to thinking again that
18 it's something that's longer than that.
19 You know, they're also involved jointly
20 in performing in the long-term planning processes
21 that we go through. And, of course, they also
22 have the collaborative process that they go
23 through.
24 But, here, again, this is the most
25 important part. It involves the stakeholders and

1 the state. I've sort of separated the state out.
2 I struggle with whether, and I don't want to call
3 the state entities a stakeholder; and I guess in
4 essence, in an overall view, that's true.
5 But, it's probably not appropriate
6 simply because they have -- different entities
7 have other obligations and things that they must
8 do in order to get their jobs done. And so
9 they're bringing those concepts to the table. So
10 I've kind of set them out apart from the
11 stakeholders, even though they are part of the
12 stakeholder group.
13 But the point is that what these folks
14 do is they provide the glue that really holds this
15 stuff together. They participate in the
16 processes, at least we're hoping that they're
17 participating in these processes. They're
18 providing the guidance and recommendations on
19 process objectives. Okay, we know what we want to
20 do with the expansion plan, but the expectation is
21 that these folks will bring forward their concerns
22 or their needs, as they seem them in terms of how
23 they view the world, they'll bring them into this
24 process so that the ISO and the PTOs can try to
25 address them.

1 They assure the continuity of the
2 information across all the stakeholder forums. To
3 me, I just think that's a given. And obviously
4 they also have a collaborative process that we
5 would like -- or that we follow with both the ISO
6 and the PTOs.
7 So, where does that leave us? There are
8 a lot of challenges. I have listed up here, you
9 know, a number of challenges that I just threw on
10 a slide. You can probably think of many many
11 others.
12 But the question is, is it enough. Is
13 what we're doing enough? The ISO, at least over
14 the last year to year and a half, has come to the
15 conclusion that no, it's not enough. That we need
16 to be doing something more than just our
17 traditional expansion planning process, our RMR
18 studies and our occasional focus planning studies
19 and so on and so forth. There's other things that
20 need to be done.
21 So what we have sort of come up with as
22 the concept -- it's not really a concept, we all
23 understand this, but regional long-term
24 transmission -- it's the piece that says, okay, we
25 go through our five- and our ten-year efforts.

1 But the question is what do we do beyond that,
2 okay.
3 I think that the Valley-Rainbow process
4 and how that ended up will probably forever stick
5 in my mind with regard to some of the things that
6 came out of that.
7 But one of the questions that was asked
8 in that process was, well, so how does this fit.
9 We understand that you're talking about need,
10 okay. And we understand that you're trying to
11 define this project based upon that. But how does
12 it really fit? Is it the right thing to do?
13 Now, I don't know about you folks, but I
14 believe that that's a very good question. And I
15 think it's a question that we sort of have been
16 missing. And we've come to a point now, and for
17 whatever the reasons were that the decisions were
18 made, just the essence of the questions alone, I
19 think, says we need to do something different.
20 And so the regional long-term
21 transmission study, at least as we see it, is
22 there to accomplish a number of things. And you
23 may see other things that it would accomplish, but
24 in concept it's there to define a master plan for
25 some of these, what I say a short-term project

1 fades, but it's really for things like the Midway-
2 Vincent line, or, you know, new 500 transmission
3 facilities that may be proposed. How do these fit
4 overall into the state, into the long return needs
5 of the state.
6 It involves the stakeholder process
7 which was probably even much more important than
8 any of the other things that are done, because the
9 key here is that you have people out there that
10 want to do things. They want to build
11 transmission; they want to build generation, okay;
12 or maybe a combination of both. And they have
13 something to say about that.
14 The problem is where do they get their
15 input; and how can it be managed in a manner that
16 allows it for that to be a meaningful process.
17 The state resource plan. Bottomline is
18 that there isn't much that the ISO can do without
19 that kind of involvement, okay. We have a lot of
20 expertise within that company. But I, you know, I
21 can't truly say that we have the right expertise
22 to do these kinds of things.
23 And so I think that one of the things
24 that the ISO has come to realize is that while we
25 have a lot of expertise in operating the system

1 and doing planning studies and establishing need,
2 there still are issues related to load
3 forecasting; there's issues related to assumptions
4 about generation and so on and so forth. That
5 there are other entities within the state and
6 other areas that are very well geared to providing
7 that kind of information.
8 And so the process needs to provide the
9 opportunity to allow that input to come in so that
10 we can take that into account.
11 The opportunities for addressing
12 reliability, economic needs and minimizing
13 environmental impacts and costs, these are just
14 standard things. We always want to do that. But
15 the reason for bringing that up here in this part
16 is that it really sort of brings another
17 perspective into what a transmission planning
18 process is.
19 It isn't just about performing technical
20 analyses, okay. It's really, it's very complex.
21 And you just don't go out and run a bunch of power
22 flows and then come up with a bunch of answers and
23 say here it is, this is what you're going to go
24 do, or this is what you should do, because it's a
25 lot more complicated than that.

1 Is five years enough? I don't think
2 anybody in this room believes that five years is
3 enough. If you do, then, you know, we probably
4 ought to have a conversation about that. Because
5 in some cases, it is; in some cases, it isn't.
6 And what I've heard from questions and comments
7 that were asked and made earlier this morning,
8 that's precisely the concern that people have. Is
9 how can we be assured that the things are going to
10 get done. Okay.
11 If you want, you know, if someone's
12 asking, well, maybe we should look at no
13 transmission growth and see how the generation is
14 going to fill in those gaps, where is that really
15 coming from. It's that concern about can it all
16 fit together. And that, I think, is what we
17 really need to try to do as groups, and the
18 diverse groups that we have, is try to find a way
19 to fit this stuff together so we can do the right
20 thing for the state.
21 As a plan, it's got to handle a lot of
22 different things. It's got to handle a lot of
23 different variables. It's got to be something
24 that's beyond ten years, because we've got to
25 drive a process that forces people to ask

1 questions that are really non technical. We have
2 to force a process where people are starting to
3 ask themselves, what is the right thing to do in
4 the future; how do these things fit together.
5 That you provide the opportunity for
6 others that are not either the ISO or state
7 organizations, but others that have interest in
8 wanting to do something, to provide in put, so
9 that they want to build a transmission. If they
10 want to build generation, and maybe they don't
11 have the opportunity to build additional
12 infrastructure to get the gasline there, what's
13 the problem with trying to work with a group of
14 individuals that say I want to build a
15 transmission line from point A to point B. And if
16 I have to try to route it over here to where this
17 person is, so it picks him up, what's wrong with
18 that. Why is that any less of an alternative,
19 okay, than any other thing that we look at.
20 Where do we provide the opportunity in
21 the process for those kinds of things to occur.
22 We don't. We need to fix that.
23 We think that -- I've kind of harped on
24 the technical part of it, but it's really a
25 multifaceted thing. It isn't just about running

1 technical studies; it isn't just about generation
2 or transmission. It's about gas infrastructure;
3 it's about water; it's about environment; it's
4 about NIMBYism; it's about a lot of different
5 things.
6 And while I cannot tell you exactly how
7 you need to put all that stuff together, I can
8 tell you that we need to be looking for a way to
9 try to make that work. So, it's a multifaceted
10 process that's going to require a number of
11 different things.
12 Now, we spent a lot of time talking
13 about the state and its needs and where we've been
14 and where we want to go and how we want to get
15 there, and who's going to be responsible for that.
16 But the bottomline is that we're not isolated. We
17 can't be isolated.
18 And so what you have is, mentioned a
19 couple of times, the process that's occurring in
20 the southwest called STEP. It was initiated by an
21 old boss of mine who initiated a process in
22 central Arizona called the CAT study, or the
23 Central Arizona Transmission study.
24 The concept that they came up was that,
25 look, we know we've got all, we've got 10,000

1 megawatts of generation that's being proposed to
2 be sited at Palo Verde, okay. I don't mean like
3 30, 40 miles away; at Palo Verde. These guys are
4 all -- you can see the plants from one spot, okay,
5 10,000 megawatts. That's how that got started.
6 And there's also a need, you got Tucson
7 sitting down here, and there's also a need, in
8 terms of Phoenix growing very quickly, how do
9 you -- where's the next transmission line to be
10 built. And we already knew because of the
11 political environment that Arizona was facing,
12 with all the generation that was being proposed,
13 that simply going in and SRP saying we need to
14 build a 500 kV line to the southeast part of our
15 service territory wasn't going to cut it.
16 What we had to do was to get all the
17 utilities in Arizona involved and say, okay, this
18 is what we want to do. What do you guys want to
19 do. And then can we structure something here that
20 maybe fits everybody's needs.
21 And so out of that was born this CATS
22 process, which was very much not anything about
23 technical studies, but a lot about getting people
24 together talking about what their needs were. And
25 then drawing a bunch of lines on a piece of paper

1 and saying, this is where I want to go, this is
2 what I want to do, this is how I'd like to
3 accomplish this. And then trying to find some
4 commonality out of all that.
5 The process worked very well. And so
6 this individual has brought this to southern
7 California and said we would like, because we got
8 this generation sitting down there, we'd like to
9 find a way to get rid of it so maybe we can export
10 to California and make some money. So maybe we
11 can find a way to develop some transmission
12 alternatives between the southwest and southern
13 California.
14 And so that STEP process was born out of
15 that. And if you think about it in terms of what
16 we want to try to accomplish in terms of long-term
17 planning, and regional planning, long term
18 planning within the state, that kind of fits very
19 well into that.
20 But at the same time we've heard some
21 comments today talking about, well, it's a bad
22 hydro year in the northwest; things aren't being
23 done up there. And it has a great impact on what
24 we do in California. And whether or not we're
25 going to be able to meet our load forecast and so

on and so forth.

And that just says to me that you can't stop with something going between the southwest and southern California. That we need to also move further north and look and try to develop some kind of process with the folks in the northwest, okay.

Now, I've dealt with pretty much all the utilities in the western United States. And, you know, the southwest, in dealing with folks like Edison and San Diego, they're pretty easy to deal with. When you go to the northwest, these folks look at things a little bit differently. And so, that's not going to be an easy process. But I think it's something that we need to do and the ISO believes needs to be done.

So, as part of our overall process with regard to developing this regional planning effort, will be also to try to initiate sort of a STEP type process with the northwest.

There's a number of things that we want to do, at least that I wanted to do. I've kind of covered all of these. I have a very great desire to refocus our expansion planning concept to a ten-year concept, which is what it was intended to

1 be from the very beginning. And I think working
2 with the PTOs we can get that fixed, because
3 that's really what they're doing. And so we can
4 make that happen.
5 That we need to improve our integration
6 of all of our ISO planning roles that we have; all
7 those circles that I showed that seemed to be kind
8 of independent processes. They all have something
9 to offer in the overall needs of planning for the
10 state. And so we need to do a better job of
11 integrating those things together.
12 My belief is the expansion plan is where
13 that ought to be done. The bottomline is I think,
14 that if you look at the transmission planning
15 communities in these PTOs and think about what is
16 the single most important thing that they do each
17 year. And that is develop their expansion plan.
18 And why is that important? Because that
19 is what they are giving to the public and telling
20 you how they are going to meet the reliability
21 obligations for the next five to ten years. That
22 has got to be important to people. It's got to.
23 So the expansion plans needs to be that method and
24 that mode to be able to accommodate that kind of
25 information. And I think we can work to do that.

1 Obviously we want to develop the long-
2 term regional plan as part of that.
3 Your process here, I think that we have
4 a lot to offer you in this process in helping you
5 refine your long-term information needs. You have
6 a lot of questions about that. We have processes
7 and expertise in place. And we can help you, and
8 we stand ready to do that.
9 Terry wants us to interact with the
10 folks. We want to be supportive where we can. We
11 think this is a great process and we think we have
12 a lot to offer you. And we would like to do that.
13 We think that you have also a lot to
14 offer us in terms of our process. There's a lot
15 of opportunities to provide the information to us
16 with regard to how we build these cases.
17 Like I said, we have expertise in doing,
18 in talking about resources and talking about load,
19 but I think, and I believe that the ISO thinks
20 that there is better expertise out there.
21 And so what we'd like to do is to talk
22 about collaborative efforts here, as I think what
23 the ISO is really interested in doing is
24 collaboratively working with people to develop
25 this information so that we can get it in the

1 process as it goes through. We can put that in
2 our planning studies and we can find what the
3 transmission facility needs are, and then we can
4 move on. So I think there's a way to do that. We
5 just need to work out the details for that.
6 I'd also heard a couple of comments this
7 morning about I think someone had mentioned
8 something about a rational development of
9 transmission system. I think maybe you might have
10 mentioned that. And I could not agree with you
11 more. I struggle with is that really happening.
12 And I don't think it's necessarily anybody's
13 fault. I think of all everybody has gone through
14 over this past three or four years, we may have
15 just lost a bit of focus.
16 And so it seems to me that people are
17 getting back on track and are trying to get that
18 focus back so that we can get the right thing
19 done.
20 The other comment that was mentioned was
21 the lack of the standardized approach to
22 developing load forecasts. And I can't agree with
23 that more, either. Because that is one of the
24 biggest issues that we have. We can put any kind
25 of loads into a power flow and we can determine

1 anything that you want. The problem is what
2 credibility does it have. And I think we need to
3 come up and develop some kind of a process that
4 lends that credibility to it so as we step through
5 all these processes that the state's required to
6 go through, that at least we can have some
7 credibility behind some of these things.
8 With that, that's all I have. I would
9 just like to again tell you how much I appreciate
10 the opportunity to speak with you. The people
11 that I've heard speak this morning and this
12 afternoon, it's pretty evident that you're very
13 much -- put a lot of thought into this and that
14 you're on the right track. We look forward to
15 working with everyone that's involved in this as
16 the process goes forward.
17 PRESIDING MEMBER BOYD: Thank you, Gary.
18 Does anyone in the audience have questions? Let's
19 see, you asked me to hold those, didn't you?
20 MS. GRAU: Thank you. Yes, at this
21 point I'd like to invite Gary -- wait, don't sit
22 down yet. We're going to have the opportunity for
23 people to ask questions of anybody on the panel.
24 So Don Kondoleon and Mark Hesters from the CEC
25 Staff, as well as myself, and then Gary and

1 Morteza Sabet and Chifong -- I don't -- if you'd
2 like to join us. And anybody else from the
3 utilities. We'll get some more seats up there.
4 And then questions from the audience, we'll be
5 happy, among all of us, the best person hopefully
6 will jump forward and answer the question.
7 (Pause.)
8 PRESIDING MEMBER BOYD: Kind of emptied
9 the audience there.
10 UNIDENTIFIED SPEAKER: Is there anyone
11 left to ask questions?
12 (Laughter.)
13 MR. SKOWRONSKI: What about the RTO
14 concept? I mean how is this going to be impacted?
15 We seem to be circumventing or skipping over
16 something that looks like it's coming down the
17 track fairly fast. Just a general question that I
18 have is how RTO impact the ISO and what changes
19 can we expect?
20 MR. DeSHAZO: Well, you're probably
21 stepping back just a tad bit before my time. I am
22 aware that the ISO has filed with FERC to become
23 an RTO, and it seems like so many other things
24 that they tend to sit on, that's one of them that
25 they are sitting on for some reason.

1 I would not even pretend to try to
2 figure out, you know, the political processes and
3 issues that are occurring, you know, between the
4 ISO and the state and FERC. The SSGWI process --
5 is meant to try to address the seams issues that
6 would be associated between the three RTOs. And
7 FERC seems to be providing that group with a lot
8 of focus and a lot of credibility in terms of
9 their efforts.
10 You know, just for the sake of knowing,
11 I mean I've asked similar questions inside and
12 I've not been able to find anyone that can give me
13 any clear answer about where we think this is
14 going to end up. I think that the ISO would
15 clearly prefer to be an RTO. Otherwise we
16 wouldn't have made that filing. That the SSGWI
17 process will hopefully work through whatever seams
18 issues that there are.
19 The ISO, you know, it's an operating
20 entity; it has a lot of expertise and background.
21 I think it's prepared to make that move. But
22 maybe it's a political issue or other issues right
23 now that it's not ready to occur.
24 MR. SKOWRONSKI: As a prospective large
25 central power generator, what issues should I be

1 looked for or concerned, if any, as the ISO
2 transforms itself into an RTO?
3 MR. DeSHAZO: Well, I'm not sure that I
4 would be the best one to answer that. My personal
5 opinion is I don't see that there should be any.
6 Other than a refocus of who has, you know, overall
7 responsibility, I don't see that the ISO
8 performing in terms of planning and how it
9 interacts with individuals such as generators or
10 transmission providers or others would really
11 change.
12 There may be some concepts within the
13 overall RTO process that would eventually need to
14 be put together and ironed out, which we don't
15 really know yet. But how I would work with you as
16 a planner in finding ways to integrate you into
17 the system, I don't see that that would change.
18 MR. SKOWRONSKI: Thank you.
19 PRESIDING MEMBER BOYD: Do you have
20 questions for each other?
21 (Laughter.)
22 MS. GRAU: Okay, thank you very much.
23 We'll move on now to Mark DiGiovanna, natural
24 gas --
25 PRESIDING MEMBER BOYD: Here comes a

1 question.

2 MS. GRAU: Oh, I'm sorry, okay.

3 UNIDENTIFIED SPEAKER: Is this the

4 appropriate time to ask for any comments about

5 transmission or is that --

6 MS. GRAU: Now is appropriate. This is

7 transmission. After that we're moving on to

8 natural gas.

9 DR. ARTHUR: Dave Arthur, City of

10 Redding. And also a member of the contracts group

11 for TANC, the Transmission Authority of Northern

12 California.

13 One of the driving forces for those of

14 us that are called munis, whether or not that's an

15 accurate description, is to minimize the cost

16 while maintaining the reliability for all of our

17 retail customers. So the retail customer is our

18 driving consideration.

19 You earlier heard discussion about Path

20 15. TANC made a very concerted effort to take the

21 lead in that effort. The best estimates are that

22 would have saved the people of California about

23 $30- to $50 million per year had that particular

24 initiative been successful, instead of having to

25 turn to the merchant transmission solution, which

1 as a result of certain FERC policies will result
2 in very high costs.
3 And the reason we weren't able to go
4 forward is because we couldn't get the time of day
5 from the involved PTO or the California ISO for
6 any type of support.
7 So, earlier I had mentioned the term
8 friction. There is nowhere in the State of
9 California where the principle of friction is
10 greater than when it comes to the issue of
11 transmission.
12 You can expand the transmission they
13 have proposed there, but what you can't get is
14 assured delivery. And so the question becomes if
15 you have responsibility to your customers, how do
16 you make forward market purchases that require
17 transmission when you're prohibited, outside of
18 ownership, you're prohibited from having assured
19 delivery?
20 So, as you think through your basecase
21 and you look at policies that would be useful to
22 recommend to the Governor, I would hope that the
23 issue of assured delivery, which for those of us
24 that see our existence as serving retail
25 customers, we would hope that assured delivery is

1 high on your list of things that need to be
2 addressed.
3 Because in the environment that's being
4 proposed for the State of California today under
5 market design 2002, assured delivery is not an
6 option.
7 Thank you.
8 PRESIDING MEMBER BOYD: Panel response?
9 Comment? Anyone have the courage to address this?
10 MR. SABET: I do. This is Morteza Sabet
11 of Western Area Power. I do subscribe to Dave's
12 notion. I think we have to separate the whole
13 concept of efficient transmission exemption. I
14 think it is misunderstood because we mix the
15 expansion with a certainty.
16 There are two dimensions to expansion.
17 I think Dave's point is well taken. You have to
18 have assured certainty in order to basically
19 incent people to invest.
20 In terms of efficiency, if this line of
21 work was a perishable good I think we know how to
22 deal with that. But the issue for expansion, I
23 think the reason we have the situation that we
24 have today stems from basically lack of or absence
25 of public policy and public good direction in

1 transmission expansion.

2 We kind of, in a sense, put it on the

3 back burner. We are not looking at it in an

4 expansive or all-inclusive fashion when we look at

5 generation and transmission planning.

6 Having been involved in the project that

7 was listed as the Sacramento area, I fully

8 appreciate the missing part which is what is good

9 for the whole good of the organization or, in this

10 case, the state. And I think, you know, the

11 initiative that the Commission is taking here is

12 the right place to address that.

13 So I do suggest we need to have both, an

14 efficient expansion mechanism, as well as assured

15 certainty with price certainty.

16 MS. THOMAS: I'm Chifong Thomas with

17 PG&E. One of the uncertainties that concerns

18 transmission planning is the fact that you --

19 assumptions changed over time. And it is, for

20 example, your planning a transmission line; a

21 slight change in low projection could shift the

22 need for the line over, could be as much as ten

23 years.

24 So it's going to be very difficult to go

25 in and go to the Commission and say, well, here we

are; we need a CPCN for a line on a certain date, just like you cannot go out and say that hey, look, by year 2018 the load in California is exactly 65,345 megawatts at 3:00 in the afternoon in August.

So that is (inaudible) to that is the fact that just because something is in a plan, assumptions change, especially now with the new world we're living in with generation that was uncertainty, where the siting of generation, the load growth, that makes it very difficult and a lot of time it's just bear with us, because when we put down a line and say a certain date, it's not necessarily that it would happen.

But it's not because we're malicious or try to do something bad to you; it's just the fact that we don't -- the assumption change, and we have to change the assumption to match -- I mean the results so that the ratepayers wouldn't be stuck with paying for something that they don't need.

MR. SABET: I would like to follow a thought Chifong triggered in my mind. When you look at the old utilities when all the services were fully bundled, it was a lot easier to assume

1 certain scenario and follow through.
2 It has basically become an extremely
3 difficult to basically run your layout plan,
4 whether it's a generation supply adequacy or
5 transmission adequacy. Very difficult to base
6 your assumptions, especially with the unbundling
7 of services and the way the information flows.
8 To give you an example, in Western, in
9 our area we were basically faced with about 3000,
10 3500 megawatts of merchant generation that came in
11 basically for interconnection to our system. And
12 how you basically lay out your basecase in order
13 to study the local, as well as regional, impacts
14 is profoundly different from one set of assumption
15 to the other set of assumptions.
16 So, we basically, we get a group
17 together and everyone basically provide their
18 input based on their self interest, as well as
19 global interest. And usually come up with the
20 right approach to deal with the issues.
21 But the fact of the matter is the
22 absence of transmission hasn't basically been
23 addressed in many forums at all.
24 In Sacramento we broadcast the
25 deficiency about ten years now. And we had

1 generators coming to us, but the transmission,
2 which is the local area transmission
3 reinforcement, as well as some regional
4 reinforcement, nobody wants to own. Because
5 generators come into the basically rescue to avoid
6 building the transmission. But yet there are
7 times that you need both transmission and
8 generation, both, whether it's local or regional.
9 And those are the issues that I think
10 should come out of your effort.
11 MS. GRIFFIN: I'm Karen Griffin from the
12 staff. I have two questions and they're both for
13 WAPA and for PG&E.
14 The first one is what is the status of
15 the Path 15 upgrade in which you're both involved?
16 And what bumps in the road are there between now
17 and the projected online date that's included in
18 staff's report?
19 And the second one is there's a press
20 report out that WAPA's considering becoming its
21 own control area when its agreement with PG&E
22 ends. And will that have an effect on the kinds
23 of transmission upgrades that either WAPA or PG&E
24 might plan to make?
25 MR. SABET: On Path 15, based on what I

1 know currently, I don't know of any bump on the
2 road, so to speak. The current plan is, you know,
3 consistent with what you have on your slides. The
4 end of 1994 is our target energization date based
5 on what I've heard from both PG&E, as well as our
6 people in the field.
7 Our people are seriously out there, you
8 know, looking at the field investigation and
9 design. And we are moving right on target by the
10 end of 1994. I don't know personally of any
11 impediment at this time.
12 I hear people talking about financing
13 issues, but I'm not really prepared to talk about
14 it.
15 In terms of our control area formation,
16 basically I can tell you this. The reason for
17 that initiative is we have several transmission
18 contracts that are expiring by 2004. Some of
19 those contracts are to the northwest, some are
20 with PG&E. We have about a majority of our
21 customers in numbers are served off of the ISO
22 grid in PG&E distribution system. And there's
23 going to be a tremendous amount of rate shock or
24 change in terms of when the contracts are going to
25 expire.

1 That is basically our aim to make sure
2 that there is not a hell of a lot of change in
3 terms of financial impact on those entities,
4 mainly end users, you know, irrigation pumps, end
5 use energies that they're basically on their mind
6 their very survival.
7 As a measure basically to, in case if
8 these contracts don't renegotiate, they're not
9 renegotiated, more or less when the status go, you
10 know, price we understand the world around us is
11 changing. There has to be some compromise.
12 Control area was conceived as an option
13 to insulate our customers against those charges
14 that basically are many manyfold, based on the
15 estimates that we have heard.
16 So that's the initiative; we are not
17 hundred percent on that track yet. We are looking
18 at our options, both control areas, as well as
19 other options to minimize the cost, and cost
20 shifted to the customers.
21 MS. THOMAS: In terms of technical
22 cooperation and studies in transmission planning,
23 we'll continue to cooperate with Western as we
24 always have been doing, and with the ISO and all
25 the other entities.

1 MR. SPARKS: I'm Robert Sparks, the
2 California ISO. I wanted to address Dave's
3 question. I don't see him in the audience
4 anymore, but he had asked a question about assured
5 delivery. I'm not exactly sure what the
6 definition of that is, but I just wanted to point
7 out that one of the primary objectives of the
8 California ISO is to provide open access to the
9 transmission grid. And also point out that any
10 participant can schedule on the ISO control grid.
11 And to the extent that there is
12 congestion preventing delivery, that's the whole
13 reason we have a transmission planning group at
14 the ISO, and that we have this collaborative
15 process to expand the grid, so that to the point
16 that it's economically the right thing to do to
17 expand the grid. And congestion costs warrant
18 building new projects to alleviate that
19 congestion, we will do so.
20 MR. SKOWRONSKI: I'd like to go back to
21 the RTO and make a comment and address it to the
22 Commission. On behalf of Duke Solar we are
23 knocking on doors to sell green power, solar
24 thermal. And we've talked to some IOUs and the
25 munis and we got a couple pushbacks from the munis

1 that this transition going from ISO to RTO is
2 creating a little bit of uncertainty which results
3 in hesitancy which, in my view, results in delay
4 of trying to get some PPAs for green power.
5 So just make a generalized comment that
6 there is this perception of uncertainty in the
7 buyers in the market. So, that's it.
8 PRESIDING MEMBER BOYD: Other questions,
9 comments from the audience? Comments amongst
10 members of the panel? I guess Dave will never get
11 our question answered as to what really happened
12 to that first Path 15 project. I'm still waiting,
13 trying to understand why a state-sponsored
14 collaborative, state-run with its partners'
15 effort, crashed and burned. But maybe some day.
16 MR. SABET: I wasn't involved in that
17 circle.
18 PRESIDING MEMBER BOYD: That wasn't a
19 question; that was a political statement.
20 MR. SABET: But I really think the root
21 cause of all this is lack of certainty. You know,
22 when we say certainty, you know, what Dave termed
23 assured delivery means cost-based transmission
24 that you can plan on for forward purchases. Very
25 very plain English.

1 As long as I think the ISO or RTOs can
2 assure people, I think there's going to be harmony
3 and people are going to be able to step up to do
4 what they need to do.
5 But right now there is a big shadow of
6 uncertainty over the RTO because of that. How
7 would the cost shift basically manifest itself
8 once you merge, you know. We have had -- we have
9 been -- over the ISO change for five years now.
10 We haven't straightened that out.
11 You basically take 15 or 16 western
12 state and form an RTO, geopolitically that's going
13 to be almost beyond human comprehension.
14 PRESIDING MEMBER BOYD: Well, at that
15 moment in time the nation-state of California was
16 just trying to figure its own Path 15 problem out,
17 so --
18 MR. SABET: I have submitted all along,
19 this is my personal opinion, nationalizing the
20 grid probably the easiest way to deal with that
21 issue.
22 PRESIDING MEMBER BOYD: Well, thank you,
23 all.
24 MR. ALVARADO: Commissioner, we have
25 heard two legs to the stool already, the

resource -- generation assumptions and we talked about transmission.

The third leg of the stool is going to be natural gas. I don't know if you want to take a short break before we move into that or just --

PRESIDING MEMBER BOYD: I would just like to press on. If people in the audience need a break --

MR. ALVARADO: Plow on through.

PRESIDING MEMBER BOYD: -- they can just step out and breath the cold air in the atrium out there.

MR. ALVARADO: Okay, well, Mark DiGiovanna is going to talk about natural gas.

MR. DiGIOVANNA: Good afternoon. Remember me? Dim the lights here.

Now that we've reached the halfway point in today's discussion, if anybody wants to stand up and stretch their legs, feel free.

Once again, my name is Mark DiGiovanna. I'm in the Energy Commission's natural gas unit. And today I'll be talking about natural gas infrastructure.

Based on the natural gas units 2002 staff report entitled, the natural gas supply and

1 infrastructure assessment, we concluded that the
2 primary growth in natural gas demand over the next
3 ten years will come from electricity generation
4 demand, or electricity generation.
5 So, as far as making assumptions about
6 what kind of infrastructure additions will need to
7 be made for natural gas over the next ten years,
8 it's really more appropriate that we wait and get
9 the input from both Lynn Marshall's presentation
10 yesterday on demand and Dave Vidaver's
11 presentation this morning on what electricity
12 generation capacity additions are going to be made
13 in the next ten years.
14 So, based on that, my presentation today
15 really won't focus so much on assumptions that
16 we're making for the next ten years, but will be a
17 little bit more kind of retrospective about the
18 type of infrastructure additions that have been
19 made for natural gas over the past couple years,
20 and which ones we know; we have names for project
21 and we know they're in the permitting process or
22 under construction and will come onstream over the
23 next few years.
24 And just to let you know that the more
25 detailed approach of making these sort of

1 assumptions for the next ten years will be done in
2 the natural gas unit's report which will come out
3 in April of this year, which is the 2003 natural
4 gas market outlook.
5 So today's discussion will focus on the
6 interstate pipeline projects, broken up into the
7 three corridors, which I will describe shortly;
8 California's interstate pipeline infrastructure;
9 our instate and one out of state now natural gas
10 storage facility; and the possibility of LNG
11 playing a role in California's natural gas supply.
12 All right, starting out with the
13 southwest pipeline corridor. California receives
14 its southwest gas primarily from the San Juan
15 Basin with additional supplies also coming from
16 the Permian Basin, and to a smaller degree from
17 the Anadarko Basin.
18 These supplies are moved to California
19 via pipelines owned by three different companies.
20 One of them is El Paso Natural Gas Company, whose
21 system is these purple lines here. I know your
22 copies aren't in color, so here. Transwestern
23 Pipeline Company which is this blue line up here.
24 And Questar Pipeline Company which owns the
25 Southern Trails Pipeline, which is right up there;

1 the brown line up on the screen.
2 Since 2002 there have been several
3 upgrades to the pipelines on these systems. The
4 first of which was on the Transwestern system, the
5 Red Rock expansion. This increased delivery
6 capacity to California by 120 million cubic feet
7 per day. And this was completed in June 2002.
8 The Questar-Southern Trails Pipeline is
9 actually an old oil pipeline that was converted
10 over to natural gas. And that has a delivery
11 capacity of 80 million cubic feet per day to the
12 California border.
13 Another conversion oil pipeline is the
14 El Paso-All American Pipeline, which actually runs
15 along the southern system on the El Paso system.
16 And that is capable of delivering 230 million
17 cubic feet per day.
18 There are two additional projects that
19 are actually -- one is actually under
20 construction, and there's another one that just is
21 before the FERC right now and that is the -- the
22 one before the FERC is the El Paso-All American
23 expansion, which is on the same route that I just
24 showed you. They're going to incrementally add
25 about 320 million cubic feet per day between

1 February 2004 and April 2005 to that pipeline.
2 The other project that El Paso has is
3 also on the All American, but it's actually on the
4 California side which this map actually really
5 doesn't show it, but it's down here at Blythe and
6 it will go up to Daggett. And there will be about
7 700 million cubic feet of capacity on that
8 pipeline, but it's really going to be more for
9 flexibility, to be able to move gas between El
10 Paso's southern system and up into the Kern-Mojave
11 area, or to move gas back, if they want to move
12 gas from the Kern River back down to the Blythe
13 area.
14 MR. TOMASHEFSKY: Mark, I promised I
15 wasn't going to ask you questions, but I am
16 retracting that. So you'll have to indulge me
17 here. The two El Paso projects, are they
18 currently in construction, or are they -- looking
19 at the 320 and the 700. Are those currently being
20 constructed, or are they --
21 MR. DiGIOVANNA: The 700 is currently
22 under construction from what I -- the California
23 lateral?
24 UNIDENTIFIED SPEAKER: The California
25 lateral --

1 MR. DiGIOVANNA: Consult the Yoda of --
2 MR. WOOD: I just had a discussion or an
3 email from El Paso today, because I asked them
4 yesterday, what was the status of that. They
5 apparently have cleared all of the routing
6 requirements associated with converting that
7 portion of the El Paso line between Blythe and
8 Daggett. So they're now in the process of
9 developing their filings to FERC.
10 Capacity on that line, they think, will
11 be between 300 and 500 million cubic feet per day.
12 And it will take them about 12 months to go
13 through the process. And with a price of around
14 15 cents.
15 So, it's not under construction yet.
16 MR. TOMASHEFSKY: But given El Paso's
17 financial situation, that's still more likely to
18 go than not go?
19 MR. WOOD: I would say so.
20 MR. DiGIOVANNA: Okay, in this next
21 slide what we've done is we've -- this is based on
22 2003, 2008 and 2013 bars here are based on results
23 from the 2002 report that just came out in
24 December.
25 And what this graph is attempting to

1 show, if you look at the black bars, is the
2 current capacity on different areas in the
3 southwestern pipeline corridor. EPS is the El
4 Paso southern system. Havasu is the Havasu
5 crossover which allows gas to be moved from the El
6 Paso northern system to the El Paso southern
7 system.
8 The third column there, where it says
9 EPN-TWR-ST, that is actually the combined capacity
10 of El Paso's northern system, the Transwestern
11 pipeline and the Southern Trails pipeline. And
12 then finally the last is the San Juan crossover,
13 which is the -- going back here, this end of the
14 El Paso northern system. It primarily flows from
15 west to east.
16 So what this chart is showing is that
17 based on the projections from the 2002 report, if
18 as much gas is going to be demanded in these
19 pipeline corridors were to flow on these
20 pipelines, this is how it compares to what the
21 current capacity is on each of those areas.
22 So as you can see, in 2003 and going
23 forward, I mean there's actually more gas that's
24 going to want to flow there than there actually
25 currently is capacity. So there will be a need

for capacity additions as we move forward. Some of that is being addressed right now with the capacity additions that are underway, or at least in the permitting process.

MR. TOMASHEFSKY: And that goes back to feeding generation growth in Arizona, then, primarily? You start looking at that, you're looking at 10,000 megawatts, depending on what the assumptions are in terms of added power generation in Arizona, you'd expect that that's really the only game in town to serve it. So therefore you get that increase in capacity --

MR. DiGIOVANNA: Right.

MR. TOMASHEFSKY: So, can you tell how much of that is targeted to California?

MR. DiGIOVANNA: How much --

MR. TOMASHEFSKY: Just off hand, and I recognize that we're going to update that forecast. Do you know that, Bill? Going to get you to keep coming up.

MR. WOOD: Basically all of that new expansion is to meet east of California requirements. Our forecast that based upon the demand that we were using as of last year, indicated that California's demand for the

southwest is going to be rather level for the next ten years. There'll be a little growth and a dip, but it's pretty much going to be constant.

So therefore, all this demand then we see is basically to meet the growth in two areas. One is the big growth in power generation in the Phoenix area; and the other is to meet the demand on the North Baja pipeline.

MR. TOMASHEFSKY: Okay, so that flows then, then it follows with that logic that Kern River then provides the incremental supply into southern California?

MR. WOOD: That is correct.

MR. TOMASHEFSKY: Thank you.

PRESIDING MEMBER BOYD: Bill, don't sit down. The lay person would look at this chart and say, gee, three out of the four trails you're talking about here, or pathways, we're in trouble this year. But I don't hear any hand-wringing over that interpretation. Comment?

MR. WOOD: I'm sorry, you said they were in trouble --

PRESIDING MEMBER BOYD: Three out of -- in three out of the four examples there, the capacity's exceeded.

1 MR. WOOD: This is for -- well, our
2 forecast is indicating here for the year 2003.
3 PRESIDING MEMBER BOYD: Right.
4 MR. WOOD: Again, --
5 PRESIDING MEMBER BOYD: We're in 2003.
6 MR. WOOD: Yeah, well, again --
7 PRESIDING MEMBER BOYD: The price of gas
8 is out of sight.
9 MR. WOOD: -- it has to do with the --
10 PRESIDING MEMBER BOYD: Et cetera.
11 MR. WOOD: That's right, we are in 2003
12 now, aren't we.
13 (Laughter.)
14 MR. WOOD: Well, the year's not over
15 with yet, so --
16 PRESIDING MEMBER BOYD: Yoda, are you
17 worried?
18 (Laughter.)
19 PRESIDING MEMBER BOYD: Okay.
20 MR. WOOD: The implication is, again,
21 we're using a long-term forecast to try to
22 indicate what's going on in the short term. And,
23 what we're trying to indicate with these are not
24 absolutes, but the need -- but the indications of
25 where new transportation requirements are going to

1 develop in the near term.
2 The Havasu crossover, for instance,
3 we're seeing that it may have to increase about
4 three times its current capacity, given the way
5 the model operated. And that indicates there's a
6 tremendous amount of growth required in that area.
7 Well, it depends upon how fast those generators
8 get built and when they come on, as to what kind
9 of impact that's going to have on the Havasu
10 crossover.
11 On the other hand we didn't model this,
12 but this is one of the things that we want to do,
13 is that El Paso south, as you can see, is running
14 under capacity the way our model operated. And
15 also the All-American pipeline is being built,
16 which is also adds onto the El Paso. So we may
17 have up to 500 million cubic feet per day of
18 additional capacity on top of what we show here.
19 Now, if the expansions do not occur on
20 Havasu and on the northern El Paso system and
21 Transwestern and Southern Trails, then that will
22 then force the market then to have to go to the
23 Permian, which our model indicates they do not
24 want to do, because the Permian, actually prices
25 there, as we know, are impacted by what's going on

1 to the east. And therefore the Permian tends to
2 be a higher priced gas than the San Juan or the
3 Rockies gas, which the model is trying to feed
4 here.
5 So, if that capacity isn't built on the
6 northern system to support the demand that we're
7 talking about in Phoenix and in the North Baja
8 pipeline, then it'll be interesting to see what
9 happens as regards to utilization of the southern
10 system relying on the Permian facilities, and what
11 kind of impact that will have on prices in
12 California.
13 We haven't run it, but my first inkling
14 is if that were to occur that the prices in
15 California will go up.
16 PRESIDING MEMBER BOYD: Thank you. I
17 wanted you to say that because were I a lay
18 journalist and saw this I would run out and write
19 an article about we're in big trouble already.
20 So, I wanted you to put the caveats on that. As
21 Bill knows, some of us sit down with he and a
22 whole bunch of other people every other week in a
23 group called the Governor's Natural Gas Working
24 Group, and talk about all these kinds of things.
25 I wanted you to share some of that with

1 a broader audience. Excuse the interruption,
2 Mark.
3 MR. DiGIOVANNA: That's certainly all
4 right. The next pipeline corridor I'm going to
5 talk about is what we call the PG&E-GTN pipeline
6 corridor. Mainly because they're the only
7 interstate that actually serves us through that
8 corridor.
9 And this is California's source for
10 Canadian gas. And it also could provide us with
11 some Rocky Mountain gas if it were to flow on the
12 northwest pipeline in background. But primarily
13 when we think about PG&E-GTN we're talking about
14 California's supply of Canadian gas.
15 And GTN did have an expansion between
16 November 2001 and November 2002; it was actually
17 in two phases. Added 211 million cubic feet per
18 day of capacity. And similar, Scott, to what you
19 were asking about in the southwest, that expansion
20 was actually to serve electricity generation
21 demand up in this area. But by making that
22 expansion, it did benefit California by allowing
23 gas to still flow to the northern California
24 border.
25 There is one other expansion that didn't

1 really have a huge effect on California which was
2 the Tuscarora pipeline, which takes gas from Malin
3 and delivers it to Reno. You know, there may be
4 some small benefit for California for serving like
5 the Lake Tahoe area, as well. Just thought I'd
6 mention that.
7 And in similar fashion, the black bars
8 again represent the current capacity with the
9 expansions that I just mentioned. So, again, we
10 can see here that actually by the time the -- when
11 we're looking at the California border capacity,
12 we're actually, this would indicate that we're
13 doing all right there without any further
14 expansions.
15 Okay, the last interstate pipeline
16 corridor that I'm going to talk about is the Kern
17 River pipeline corridor. The Kern River natural
18 gas pipeline serves California its primary source
19 of Rocky Mountain gas. There have actually been
20 several upgrades that have taken place on this
21 pipeline, and another very big one planned for
22 this year.
23 The first one was the emergency
24 expansion which added 135 million cubic feet per
25 day of capacity in the summer of 2001. This would

1 have been right at the height of the energy
2 crisis. And the following year in May of 2002
3 that expansion was actually removed and replaced
4 with a larger 146 million cubic feet per day
5 permanent expansion.
6 More importantly, Kern River is in the
7 process of adding, more than doubling the capacity
8 on that pipeline, adding 906 million cubic feet
9 per day to their pipeline, which would bring their
10 total capacity to around 1750 million cubic feet
11 per day. So that is a very significant expansion.
12 One other addition here; it really
13 doesn't have anything to do with interstate
14 capacity additions, but it is on the Kern River
15 pipeline, is the High Desert lateral, which takes
16 gas from the Kern River pipeline for delivery to
17 the High Desert Power Plant, which is scheduled to
18 come online this summer.
19 And now looking at Kern River their
20 current capacity right now about 845 right here;
21 that's obviously going to get into here, so we'll
22 be doing all right for a little while. But
23 because of the relative low prices in the Rocky
24 Mountain region, there is going to continue to be
25 increased demand for Rocky Mountain gas to

1 California. So, you know, there will be demand
2 for either further expansions on the Kern or
3 further capacity capabilities of delivering gas
4 from the Rocky Mountains, whether it's Kern or
5 otherwise.
6 All right, moving to the intrastate
7 pipelines. This is a rough schematic of the PG&E
8 system. PG&E has made one expansion, one fairly
9 large expansion in the past year and that was the
10 Redwood Path expansion, which was around this area
11 up here. Increased capacity, receiving capacity
12 from the northern California border by about 179
13 million cubic feet per day.
14 Just want to point out that the PG&E
15 system does have unique capability, compared to
16 the other major utilities in California, is that
17 it can actually take gas from all three of the
18 intrastate pipeline corridors directly through
19 Kern River, the southwest and also from the PG&E-
20 GTN.
21 MS. BAKKER: Mark, would you mind
22 showing me where the storage facilities are on
23 that map there?
24 MR. DiGIOVANNA: Okay, I have a better
25 one coming up, but --

1 MS. BAKKER: Okay, okay, well, let's
2 wait then. I'm sorry.
3 MR. DiGIOVANNA: Okay. Kind of in the
4 spirit of what we were doing with the interstates,
5 just want to show you here this is also based on
6 the 2002 natural gas supply and infrastructure
7 assessment. And this is just to back up what I
8 mentioned at the beginning of this discussion,
9 that this is the demand by sector versus the
10 receiving capacity in the PG&E system. And this
11 is just to show that the largest and most rapidly
12 growing sector in there is electricity generation.
13 And on to the Southern California
14 system. Now, Southern California has actually
15 made several expansions since the energy crisis
16 back in 2000-2001. The majority of them are to
17 increase the receiving capacity into its system.
18 Plus there's one additional one that actually
19 increases its capability to deliver gas to the San
20 Diego system.
21 The first of which is the Wheeler Ridge
22 expansion, which increases capability by 85
23 million cubic feet per day to take delivery from
24 California instate production and from Kern River
25 and PG&E. That was up in here.

1 It also increased the North Needles
2 compressor station so that it could increase its
3 receiving capacity off the Transwestern system by
4 50 million cubic feet per day. And this is right
5 up here by the southern California border.
6 It completed the Kramer Junction
7 interconnect which was a 200 million cubic foot
8 per day expansion, which allows it to take gas off
9 the Kern River pipeline right over here at Kramer
10 Junction, down onto its system.
11 And finally, the Line 85 Sylmar
12 compressor station expansion, which increased its
13 capability by 40 million cubic feet per day to
14 take deliveries from California production.
15 And then the last one is the Line 6900
16 upgrade which was right down in this area. And
17 this here was -- right now San Diego, the San
18 Diego Gas and Electric system does not have a
19 direct connection to any of the border delivery
20 points, so when it receives gas from the
21 interstates it actually has to do it through the
22 southern California system. So this actually
23 increased its capability to take interstate
24 pipelines.
25 And one thing that I didn't mention

1 before was the completion of the North Baja
2 pipeline along the southwestern corridor.
3 Also, remove some demand from the San
4 Diego area, so that -- because the northwestern
5 Mexico was receiving its gas via the San Diego
6 system, which was, of course, receiving it through
7 the Southern California system. So, the
8 completion of those two projects both took some
9 demand out of the San Diego area, plus gave it
10 some additional capacity to bring gas into its
11 system. So that will definitely benefit the San
12 Diego area.
13 And just like in the PG&E area, the
14 electricity generation demand is the fastest
15 growing segment of demand.
16 For you, Susan. Another way that
17 California can improve its infrastructure is,
18 other than being able to bring more gas into the
19 state, is to be able to keep more gas in the
20 state. You know, when we have low demand periods
21 and then use it during high demand periods.
22 And California has undertaken a couple
23 projects, and will undertake a few more to
24 increase its capacity to do this.
25 The first project was in the southern

1 California area, and this was at the Aliso Canyon
2 and La Goleta storage facilities. And these are
3 down here, number 6 and 8. And these were
4 existing facilities that in the summer of 2001
5 they were able to convert some of the cushion gas
6 in the system to working gas. So it actually
7 increased the capacity combined between the two by
8 14 billion cubic feet.
9 The next big addition for California was
10 the Lodi; Western Hub's Lodi gas storage facility,
11 which began operation in effectively January of
12 2002. And that added another 12 billion cubic
13 feet per day -- or not per day, billion cubic feet
14 of storage capacity in northern California.
15 And then in the coming years both PG&E
16 and EnCana at Wild Goose will increase, have
17 expansions of their facilities that will increase
18 the storage capacity in northern California by
19 almost 22 billion cubic feet.
20 And then the last project listed here is
21 the one out-of-state project which the Red Lake
22 storage project. And that project right now is,
23 it just received its approval from FERC based on
24 non environmental review. So it's still pending
25 environmental review. But that will -- the

1 storage capacity there will be to serve east of
2 California demand, but it is also -- there is some
3 storage that will serve California customers, as
4 well.
5 So just having the storage near the
6 border to serve regions that would otherwise be
7 demanding, you know, competing with California for
8 demand on the pipelines, plus also serving some
9 customers in California will benefit the state.
10 MR. TOMASHEFSKY: Is it tied just
11 directly to Southwest gas, or Kern River, as well?
12 MR. DiGIOVANNA: It's actually going to
13 be connected to the El Paso northern system. It's
14 kind of hard, without the pipelines there --
15 MR. TOMASHEFSKY: Okay.
16 MR. DiGIOVANNA: The last slide. I know
17 there's been a lot of press about the possibility
18 of LNG becoming a supply source for not just
19 California, but for the western side of North
20 America, considering there are no terminals right
21 now.
22 Right now the three terminals that I've
23 included in this graph are the three that have
24 actually filed permits with the Mexican
25 authorities to build projects near the southern

1 California border with Mexico. All in the Baja
2 region.
3 The likelihood is that not all three of
4 these would, you know, if they were permitted,
5 would be built. And there are also -- there are
6 proposals to still try to build a facility in
7 California. But none have gotten this far as
8 actually filing for permits as these ones have
9 here.
10 And with that I will open it up to
11 questions.
12 MS. BAKKER: I have a couple of
13 questions. Your two graphs that show the
14 receiving capacity compared to the demand. And if
15 I understand the graph correctly, the demand is
16 expressed in an average sense, an average daily
17 demand.
18 Have you looked at how that compares to
19 a peak demand?
20 MR. WOOD: Basically what we're trying
21 to show with this map or this graphic, we show the
22 receiving capacity and the annual average demand
23 in regards to millions of cubic feet per day. The
24 interesting thing when we put this map together,
25 or this graphic together was to try to indicate

1 what kind of slack capacity there might be on the
2 system. Slack capacity is thought to be that in
3 order to meet the seasonal requirements your slack
4 capacity on annual average basis should be 15 to
5 20 percent.
6 And what we were trying to indicate here
7 was that for the SoCal system currently, given the
8 huge amount of additions that they did to their
9 system in the last two years, that they're now,
10 their slack capacity is somewhere in the area of
11 about 40 percent.
12 And that by the end of our study period
13 that we have here they'll be down to about 20
14 percent. So therefore they have basically built
15 in the capacity.
16 If you were to use a slack capacity
17 factor of 20 percent as a rule of thumb to shoot
18 for, that's what this graph is trying to indicate
19 to us. If they hadn't added that on, then they
20 would have been in the same situation as PG&E --
21 MS. BAKKER: I understand that, but I
22 guess I read your report and one of the things it
23 said was that the PUC had established the 20
24 percent figure.
25 MR. WOOD: Yes.

1 MS. BAKKER: And it used average
2 temperature. And hydro, average hydro, average
3 temperature. And the question I had was have you
4 looked at that 20 percent criterion that is the
5 planning level you would shoot for, or using that
6 receipt capacity, actually, against a peak day in
7 an extreme set of assumptions.
8 MR. WOOD: Well, we have not looked at
9 it specifically in that regard. And our concern
10 would be not so much associated with a peak cold
11 day requirement or a series of days that were cold
12 in the wintertime, because storage would fill into
13 this.
14 Demand, for instance SoCalGas currently,
15 as their capacity, receive 3800 million cubic feet
16 per day. In addition they can pull another 3000
17 cubic feet per day out of storage. And you put
18 this all together, they have the ability to meet
19 about 6 billion cubic feet per day of demand on
20 their system. They've only hit that or come close
21 to that once or twice.
22 MS. BAKKER: But we've had a change in
23 structure. You've said it over and over again,
24 from the first person that stood up here to the
25 last, that now natural gas demand is driven by

1 electric generation. The change in natural gas
2 demand.
3 So, what I think could be happening, I
4 don't know for sure, because I haven't seen
5 numbers, is that we have now two peaks, two times
6 when we need to rely on storage instead of one.
7 And if that's the case, we may be facing new
8 challenges.
9 MR. WOOD: Well, there's always been two
10 peaks. And it's always been that the winter month
11 is a higher peak than the summer month. And --
12 MS. BAKKER: But we don't know if that's
13 going to continue with the change in electric
14 generation.
15 MR. WOOD: We have -- well, to some
16 extent David Vidaver has provided the hourly and
17 weekly, and we have looked at, at least in the
18 summertime, what that peak requirement is. And
19 we've always had sufficient capacity to meet that
20 particular requirement.
21 The problem is -- well, to boil it down
22 to -- I'm not going to go into this any further,
23 but the thing is, yes, we need to look at that.
24 That's one of the things that we want to be
25 looking at during the remaining portion of our

1 period between now and April. We're hoping to be
2 able to have the time to be able to look and look
3 at that. If not, then we may have to put off that
4 until the next round when we do it.
5 But that is definitely something that
6 I've wanted to look at for the last four or five
7 years. And we just are in the process now of
8 developing the tools to be able to do it.
9 MS. BAKKER: It takes a lot of extra
10 assumptions probably to do that.
11 MR. WOOD: Well, for one thing, our
12 demand office only looks at annual gas demand
13 forecasts. And we need from them the peak
14 requirements, peak day requirements so that we
15 can -- and they don't do seasonal forecasts for
16 us, they only do the annual. So we need a
17 seasonal forecast. We can develop one based upon
18 the historical shares --
19 MS. BAKKER: Records, yeah.
20 MR. WOOD: -- for each month. But we
21 haven't taken that step yet. But we may have to
22 do that.
23 MS. BAKKER: Thank you.
24 MR. TOMASHEFSKY: What that really
25 shows, that's part one of the puzzle, is that

there's this receiving capacity question. And then you have actually delivery capacity is another question.

MS. BAKKER: Right, that's --

MR. TOMASHEFSKY: So if you look at that as a peak --

MS. BAKKER: -- that's not something we've even looked at here, right?

MR. TOMASHEFSKY: Right. So, from a standpoint of SoCalGas' claim that they haven't had a curtailment, well, they haven't technically speaking because they really ramped up capacity, delivery capacity to almost 7 bcf a day. So by virtue of doing that you have slack capacity.

Now how you define that on an average day or a peak day you have to really give it a lot of thought as to how to present it.

MS. JONES: Well, there's also some pretty severe cost consequences associated with running up at those levels, as we saw in 2000 and 2001. So it seems that that's a very important contingency for the Commission to be assessing.

MR. ALVARADO: Well, I'd like to also add, Susan, to your question. I think that is part of the game plan. David has explained some

of the different scenarios we want to try to evaluate. At least from the electric generation side we will consider some of these low hydro scenarios and see what would be the consequence of fuel demand for electric generation.

That piece will then be passed on to the gas folks and hopefully they can evaluate to see what the implications are to the gas system, too, as part of our integrated part of the report here.

MS. BAKKER: Right.

PRESIDING MEMBER BOYD: I'm looking forward to that. I'm even looking more anxiously forward to when you start adding in supply potential and where it might all come from once we decide demand and the capability of the infrastructure, intrastate and interstate, to move gas around. I want to know is it even there. Or what do we do. So, April is going to be exciting.

MR. PRUSNEK: My name is Brian Prusnek from the CPUC. Also in answer to your question, Susan, yes, that is the receiving capacity of the utilities there, for example, what they've been showing.

And I guess the question is on a peak day is there enough, and this is what we kind of

1 got into, is the deliverability there to get to
2 it.
3 The instate aspect of it is CPUC does
4 require the utilities to have their natural gas
5 pipelines built to serve an abnormal peak day on a
6 cold winter day --
7 MS. JONES: But that's only for the core
8 customers, correct?
9 MR. PRUSNEK: Well, that's how large
10 their pipelines have to be built to serve the core
11 customers. And we have imposed some of those
12 conditions, or stricter conditions, on the
13 southern California systems.
14 But there's also --
15 MR. TOMASHEFSKY: Based on the --
16 MR. PRUSNEK: -- curtailment, then. If
17 we start pushing into the core customers we also
18 have curtailment rules in which the core customers
19 can curtail.
20 But on peak days we also have the
21 ability to pull gas out of storage and there's
22 also 15 percent of our gas consumption is from
23 instate production, as well.
24 So the question really does go to can
25 the intrastate pipelines deliver that. And unlike

1 instate where we can require slack capacity,
2 especially on the receiving end of the pipelines,
3 the interstate, we would have to actually pay
4 quite a bit for that. And we would have to sign
5 up for that capacity, to get that equivalent slack
6 capacity there.
7 So the question is do we have the people
8 there to sign up for the intrastate capacity to be
9 able to get that peak day delivery. And I would
10 be pretty sure that the companies that need to
11 take gas off the interstate pipelines are taking
12 enough to meet their peak day needs.
13 MS. JONES: Well, I think there's an
14 important caveat that you have to talk about when
15 you talk about the intrastate system and storage.
16 That's assuming that the storage is there.
17 And we've had circumstances where the
18 storage was used and not available when we had
19 peak demand conditions.
20 MR. PRUSNEK: Correct, and --
21 MS. JONES: So it's not just the storage
22 capacity, it's whether there's conditions that are
23 conducive to putting the gas in storage and --
24 MR. PRUSNEK: That is correct. And we
25 have imposed certain storage obligations upon the

1 utilities for their core customers. Noncore
2 customers can do whatever they want with the
3 storage. And that's a question we need to look
4 at potentially in the future.
5 MS. JONES: I think one of the important
6 things for us, in terms of looking at the largest
7 part of the demand growth in natural gas use is
8 the electric generators, and they are not part of
9 the core. And so how do you adequately plan for
10 them and their needs?
11 MR. PRUSNEK: That is --
12 MS. BAKKER: Right, so it doesn't do you
13 much good if you're curtailing electric generation
14 so people can't run the fans on their heaters, to
15 have gas. So, you got to cover the whole picture.
16 PRESIDING MEMBER BOYD: Well, here we
17 are again where we were two years ago --
18 MS. BAKKER: Yes.
19 PRESIDING MEMBER BOYD: -- to see if the
20 people are going to put gas in storage starting
21 March and April, with the prices where they are.
22 And, you know, having been burned before that
23 with, as already said, no gas in storage. So
24 watch this moving target.
25 MS. BAKKER: Thank you.

1 MR. ALEXANDER: Michael Alexander with
2 Southern California Edison Company. And I just
3 wanted to, while we're on the subject of storage,
4 point out that although we tend to think of
5 storage mostly in terms of this graph of average
6 or peak day delivery, it's also important to
7 realize that it's a key component of managing a
8 system in terms of balancing, in terms of price
9 control and everything else.
10 And it's only kind of been talked about
11 in the report, which is a good report; this isn't
12 criticism, it's a suggestion, as a substitute for
13 immediate end-use delivery. But I think we have
14 to, in order to really look at the system, look at
15 its use for price control and for balancing, as
16 well.
17 And it may require a very different set
18 of assumptions as electricity grows than we've
19 used in the past.
20 MS. BAKKER: Good point.
21 DR. ARTHUR: Dave Arthur, City of
22 Redding. It's very instructive to compare the
23 opportunities that are available on gas and also
24 look at what has happened in gas transmission to
25 the electricity side.

1 And earlier I think I used the term
2 friction. On the gas side if you feel you need
3 assured delivery, you can go out and become a
4 shipper. Now, in the case of getting from Malin
5 to the Canadian Basin, you can become a shipper
6 for 20 years or longer.
7 In the case of California the current
8 limit is one year for assured, which is a source
9 of grave concern to us. But to their credit, PG&E
10 is making a number of constructive suggestions in
11 their most recent gas court filing and hopefully
12 we will make progress in that direction.
13 Now, what's really interesting is if you
14 become a shipper, that is to say you pay your pro
15 rata share of the entire cost of that pipe, you
16 actually get to use it. Which is actually very
17 typical within the normal commercial world.
18 But if we go over to the electricity
19 side, if you pay your pro rata share of the
20 transmission system, which all end users do under
21 the current model of California, what it does is
22 it gives you the right to bid to use the system.
23 Be kind of like going to an airport and
24 you paid for the ticket and you get there and they
25 say, you're now entitled to bid to see whether or

1 not you get on the airplane or not. Which, of
2 course, is not the way it works; if they've over-
3 subscribed the airplane they have to pay you to
4 not get on the airplane.
5 So I think it would be helpful when we
6 create the baseline to point out the fundamental
7 distinctions that exist in the gas world and in
8 the electricity world. And as we look at policies
9 to eventually consider and to recommend to the
10 Governor, it seems to me that we might take a lot
11 of lessons from the gas world.
12 We might note that expansion has
13 actually been going on in a very regular basis in
14 the gas world. You saw a list of the number of
15 actual expansions that have occurred in the gas
16 world. I can assure you you will not find those
17 same number of actual expansions in the
18 electricity transmission world.
19 And you will find that those are purely
20 cost-based expansions, which helps keep the cost
21 down, assurance up, and again leads to lower
22 prices for the retail customer.
23 And then the last point I'd like to make
24 is using the City of Redding as an example, we are
25 a classic case of the inseparability between gas

1 and electricity, because we have just completed a
2 new power project within the city limits of
3 Redding, which, under certain circumstances, could
4 provide anywhere from 50 to 75 percent of the
5 electricity required by the citizens of Redding at
6 a moment in time.
7 That plant runs on gas. As you just
8 heard, the planning criteria have been to take
9 care of core. Those core people that are being
10 referenced are also electricity consumers. And in
11 order for them, as was astutely observed by the
12 Commissioner, in order for them to run their
13 forced air gas heaters, they're going to need
14 electricity.
15 And so the notion that we can treat core
16 and noncore somehow as distinct entities is, I
17 think, probably appropriate to times past, but may
18 not be appropriate as we go forward. And so I
19 hope that again we will look at the sort of
20 inseparability of gas to electricity.
21 And just as an aside, Redding got very
22 involved in gas because as you go to gas-fired
23 generation you discover that the costs of gas
24 become your single largest cost of providing
25 electricity to your consumers. So it becomes an

1 issue of enormous importance to you.
2 And so we no longer see them a
3 separable. But what we have discovered, because
4 we're new to the gas business, frankly, we've
5 discovered that while all of this restructuring
6 that we've heard about was alleged to be
7 replicating what went on in gas, we've discovered
8 that there's very little relationship to the
9 restructuring that has gone on in electricity, and
10 the restructuring that's gone on in gas.
11 Gas actually is fairly logical. In our
12 view, electricity is not.
13 MR. HALL: Hello; my name is Stephen
14 Hall. I'm not representing anyone. My background
15 is I've been in efficiency and renewables for 22
16 years.
17 And what you've presented here today is
18 essentially a model that says that you're going to
19 meet natural gas demand through expanding natural
20 gas supply infrastructure.
21 And I wondered if the Commission has
22 done any analysis to look at supplying natural gas
23 infrastructure by suppressing demand, by making
24 natural gas energy end uses more efficient. That
25 is to say making our furnaces, our water heaters,

1 our windows, our boilers, our cogeneration systems
2 more efficient.
3 And what that would translate to in the
4 number of pipelines, storage facilities and so on,
5 that would be avoided by making those end uses
6 more efficient.
7 For example, we have about 6 million
8 furnaces in northern California that could be
9 improved by their end use efficiency by 40
10 percent. We can immediately improve the gas water
11 heater efficiencies by 20 percent by commercially,
12 off-the-shelf technology. And we could do this
13 with windows, boilers and cogeneration systems.
14 And I wondered if the Commission had
15 done any analysis on the demand side that would
16 show what the equivalent impact would be on the
17 natural gas system.
18 MS. BAKKER: I saw Lynn Marshall in here
19 earlier; I don't think she's here anymore.
20 MR. WOOD: I know that we have one
21 division and one office in that division that is
22 specifically involved with developing
23 conservation. I think the State of California is
24 the lead with regards to imposing conservation
25 into our systems, both in regards to appliance

1 standards and building standards.

2 For your information, I have tracked the

3 average utilization of a residential home since

4 1965. In 1965 the average home used about 125,000

5 cubic feet per year. The most recent information

6 I saw indicates that is now at 55,000 cubic feet

7 per day (sic).

8 So, while residential hookups continue

9 to grow, the utilization per household has

10 continued to drop. As a result you can see the

11 residential demand here is fairly constant, both

12 for SoCalGas and the PG&E service areas;

13 indicating, yes, the conservation standards that

14 the Energy Commission put into place and have been

15 putting into place since its inception, 1975 or '6

16 timeframe, has had an impact both on the building

17 stock that is being brought into California, as

18 well as those appliances that are being used

19 within the state.

20 So, yeah, I think we have taken those

21 kinds of things into account to trim things

22 further down. Then at the 55,000 cubic feet per

23 home, would actually then have to require going

24 in, I think, and doing retrofitting of the old

25 stock requiring things to be done. The old stock

1 meaning the old homes.

2 I think for the most part, I don't know

3 what the life expectancy is for furnaces and for

4 air conditioners and for other hot water heaters,

5 but basically most of that sort of stuff will be

6 phased out. The old stuff, the old inefficient

7 units are being replaced by the more efficient

8 units.

9 Now, there is a range. You know, if you

10 want to put in a new hot water heater there is a

11 range in terms of how efficient each of those

12 units are. But overall they are in better

13 condition than they were, the original stuff that

14 was put in the home. In addition, our

15 requirements are much higher than they are

16 anyplace else in the nation.

17 MS. JONES: Well, I think the gentleman

18 does have a very valid point here. Yesterday when

19 we talked about the electricity demand, we looked

20 at the things that we, you know, expect to occur

21 that are included in the demand forecast; and had

22 a discussion about additional energy efficiency

23 opportunities that might be available to defer

24 investments in power plants and other things.

25 And I think it's valid to ask the same

1 questions on the natural gas side. Are there
2 additional opportunities for energy efficiency
3 that mean that you can defer investments in
4 natural gas infrastructure.
5 MR. HALL: Yeah, I mean what I'm
6 basically suggesting is that rather than making
7 energy policy on the basis of your helplessness in
8 terms of demand forecasts and scenarios, that you
9 can make conscious decisions which you can control
10 to turn over the furnace and water heater stock.
11 I mean the Commission turned over the
12 refrigerator stock over the last 20 years very
13 successfully. And if a program was put in place,
14 you could turn over the 6 million furnaces in
15 northern California and immediately realize a 40
16 percent decrease in gas demand in the residential
17 sector.
18 PRESIDING MEMBER BOYD: I was going to
19 answer your question with a simple yes. But it
20 deserved more than just that. And I'm glad Bill
21 stepped to the fore. I think --
22 MR. HALL: So will it be possible to see
23 an analysis on the demand side?
24 PRESIDING MEMBER BOYD: Well, I'm not
25 going to --

1 MR. HALL: Of natural gas.

2 PRESIDING MEMBER BOYD: I think that's

3 something we want to do. I think, you know,

4 there's a heavy dedication in this agency now to

5 efficiency. And that's a very logical question.

6 And as we go through the iterations

7 we'll see, although I see the Project Manager

8 standing at the microphone and she may have an

9 opinion here.

10 MS. GRIFFIN: The answer is yes. This

11 is another problem of right now we're just

12 sunshining bits of the pieces. There's a whole

13 other section which is working on the energy

14 efficiency potential, the cost effective

15 potential.

16 And one of the primary policy questions

17 which was brought forth by the Commission in its

18 scoping order, and that we're working on, is is

19 there a level of energy efficiency which we would

20 like -- which the state would like to set as a

21 goal in terms of doing that first.

22 So, it's definitely the idea that we've

23 now identified a renewable portfolio standard,

24 that in terms of doing that first on the

25 generation side. Now the question is even before

1 we do generation should we be doing something more
2 explicitly in energy efficiency and demand
3 response.
4 Another wave of people; another wave of
5 reports in May. So, yes, we're definitely trying
6 to meet the concern you've raised.
7 MR. HALL: Okay.
8 MR. HALL: You know, I'd like, in terms
9 of recommendations that you want to come up with,
10 the five or six or seven major things that you'd
11 like to come up with, I'd like to suggest that you
12 look at establishing a least total cost integrated
13 natural gas resource plan that's based on a
14 dispatch order of energy efficiency, renewables
15 and down the line.
16 I've addressed the energy efficiency
17 part in this section, but I have lots of comments
18 about renewables versus gas combined cycle for the
19 next section.
20 PRESIDING MEMBER BOYD: Thank you.
21 MR. HAMPTON: Good afternoon; my name is
22 Kent Hampton; I'm with Marathon Oil Company and I
23 represent one of the companies that is proposing
24 to bring LNG into Baja.
25 It appears throughout these

1 presentations that California is increasing its
2 dependency on natural gas; that coal, oil and
3 nuclear power is certainly not in favor.
4 As a gas peddler I think that's a great
5 thing. But, as a public policymaker that's
6 probably not a good thing.
7 And that raises, to me, the importance
8 of a diversity. If we're going to put all our
9 eggs in the natural gas basket, diversity of
10 supply, and speaking not just for our project, but
11 for any of the LNG projects, that's really one of
12 the services that they would provide. Another
13 source of gas.
14 And probably that source would come from
15 South America, from Alaska or from Southeast Asia.
16 The spikes that we've seen here recently that Bill
17 talked about are evidence not of just a
18 California-centric problem, but it's a bigger
19 problem now. We're having some deliverability
20 problems in the lower 48 and the traditional
21 basins of Canada.
22 So, to me, I think you have to look at
23 LNG as not just a gas supply, but as some diverse
24 sources. Another way of perhaps controlling your
25 dependence on natural gas, traditional natural

1 gas.

2 Lastly, I wanted to point out we were

3 talking -- Mark was talking about storage. One of

4 the other things that LNG brings is storage. We

5 would have, and I'm sure the Sempra and the

6 Chevron Texaco projects and Shell projects will

7 all have storage onsite, 6 billion cubic feet.

8 It's very high deliverability storage.

9 And that's not something that usually

10 strikes people when they think about LNG. But it

11 has the ability to meet load very quickly.

12 Thank you.

13 PRESIDING MEMBER BOYD: Thank you.

14 Those of us who follow this very closely are aware

15 of all that you said about LNG. We've barely

16 touched the surface. I'm expecting when we get to

17 the supply discussion there will be a lot more

18 talk about LNG. There certainly has been a lot of

19 talk about it within the halls of this building in

20 the past many many months. But I appreciate your

21 comments.

22 There's a lot of friction, to quote the

23 gentleman in the audience, associated with LNG;

24 more friction north of the border than south of

25 the border of the Californias, so it's a hurdle to

be dealt with.

I look at LNG as kind of the big pipeline from the west. And if the pipelines from the east don't respond to need and we can't reduce our demand all the way through efficiency, then, yeah, we need a supply.

MR. MELDGIN: I want to rephrase a question of Susan Bakker's, I guess. One way of looking at that is given the growing demand for gas or electric generation, the risk of drought and so on, what's the appropriate level of slack capacity. Maybe a different number is appropriate now.

And awhile back the CEC had a report; Dr. Weatherwax was here talking about running different temperature and precip scenarios around a basecase for some future year. And then somehow integrating gas and electricity to get at that question. I'm just wondering where that whole effort stands.

MS. JONES: Well, it's an area of active interest for this Committee.

PRESIDING MEMBER BOYD: Yes.

MS. BAKKER: Yes.

PRESIDING MEMBER BOYD: Well, the

1 Electricity and Natural Gas Committee on which I
2 sit is very interested in that, but some staff
3 member can perhaps --
4 MR. ALVARADO: Well, I know that among
5 staff we -- you know, I know there has been
6 meetings and Mark has come to talk to us. And we
7 are trying to examine different capabilities that
8 we can engage in that kind of effort.
9 Considering I wasn't part of that
10 discussion, sorry, I don't really have an answer.
11 But it is something that we'd like to consider.
12 PRESIDING MEMBER BOYD: Well, let me
13 just assure the gentleman that there's been a lot
14 of talk about it, an extreme amount of interest in
15 it, a very keen desire to engage deeply in doing
16 that. And right now I'm sure we're bumping up
17 against resource constraints, both person power,
18 of which we can't get any more of, and this budget
19 situation, and dollars, which we can't get any
20 more of.
21 So we will be balancing our resources
22 against the workload we face, as well. But, yes,
23 some of us are very interested in that. I mean
24 it's just part of looking at the whole system. If
25 you're in the 21st century you've got to look at

1 the whole system and all the components thereof.
2 And it's a struggle.
3 MR. PRUSNEK: Brian Prusnek from the
4 CPUC. One last comment I'd like to make. I would
5 like to congratulate the gas group. The CPUC and
6 the CEC do work quite a bit in the field of
7 natural gas together. And I would like to
8 publicly congratulate the CEC gas group on their
9 efforts they have been doing on this.
10 You know, they've been pushing out
11 reports like crazy here recently. And they have
12 another one coming out in April. And we look
13 forward to reading that and helping them and
14 commenting on that, as well.
15 Thank you.
16 MS. BAKKER: Thank you.
17 PRESIDING MEMBER BOYD: Well, thank you.
18 I happen to know that, you know, when the gas
19 group meets every other week you're there on the
20 phone. In fact, I finally met a voice today, who
21 I'd never met before, from the PUC, introduced
22 herself. She's just been a voice on the telephone
23 now for a long, long time. But, anyway.
24 MR. MARCUS: Good afternoon; I'm Bill
25 Marcus, I'm representing The Utility Reform

1 Network, TURN. I'm here to play Mike Florio; I'm
2 not Mike Florio. But I do have a couple of brief
3 observations --
4 PRESIDING MEMBER BOYD: Let's see how
5 close you get.
6 MR. MARCUS: -- on gas that came out of
7 what I was hearing. And one of them has to do
8 with the storage question.
9 One of the problems we have is that we
10 deregulated storage in 1993, and basically we no
11 longer have a situation where everybody in the
12 state is responsibility for reliability. The only
13 people who are responsible for reliability on the
14 storage side of the world are the core customers.
15 The noncore customers can do whatever
16 they want. And in the year 2000 they did whatever
17 they wanted, which was to pull all their gas out
18 of storage in the month of November. That's
19 probably the single basic reason why we racked up
20 billions and billions of dollars in debt in this
21 state. And yet it seems to receive very little
22 attention in the overall scheme of deregulation.
23 Maybe we need, if you're going to be a
24 gas player in the state with the electric system,
25 maybe you need to be a player in the storage

1 system along with everybody else in the state to
2 make sure that things are kept on a reliable
3 basis.
4 Second quick observation is that we have
5 had rate design policies for a number of years
6 which encouraged people not to build gas.
7 Essentially the whole marginal costing rate design
8 practice, as done for intrastate pipelines, and
9 this is changing with the new gas accord and a
10 couple of things, and those changes are probably
11 for the good, but what they basically created a
12 situation was where the electric generators
13 basically had to say they never needed any more
14 pipeline. Because they would not only have to pay
15 for what they needed, but they'd have to pay for
16 their share of the embedded system. And they got
17 away without paying for it for a number of years.
18 I think we're moving away from that.
19 But we still have the question of essentially
20 making sure that we build what we need, and we
21 don't end up dumping the costs back on the core
22 customers because they're the only ones you can
23 force to pay for them.
24 And I think those are my observations
25 for this afternoon. I'll come back when we get to

1 cost of generation. Thank you.

2 PRESIDING MEMBER BOYD: Thank you.

3 MS. JONES: Thanks, Bill.

4 MR. ALVES: My name is Joe Alves; I work

5 with BP Energy, and I've had the pleasure of

6 working for SoCalGas in procurement for six years.

7 And I now have the pleasure of working for BP

8 marketing power plants. And it's a very difficult

9 challenge.

10 Everybody takes risk in the market.

11 Power plants build generation and they're looking

12 for a long-term power contract. Producers, like

13 ourselves, try to find natural gas. We take risks

14 in E&P. Other companies take risks on transport

15 and storage.

16 So everyone needs to share in the risk.

17 One thing I've noticed is power plants want gas on

18 demand.

19 I want to echo the comments on storage.

20 Generally utilities go out, I'm talking about

21 IOUS, and they pay for reserve capacity. And they

22 pass that through in their rates.

23 But we see on the storage side they

24 don't go out for capacity, nor do they want to own

25 it. Who wants to own storage this year? This is

1 a repeat of 2000. And I lived it in '96/97 with
2 SoCal buying gas. I lived it in 2000 selling it.
3 We have backward-ization in the market
4 which is a real fancy word that's saying that the
5 prompt month is more expensive than the future
6 months. So when I'm looking at buying gas at $6;
7 paying the utilities $1 for storage; and I can't
8 hedge it forward in the winter, I'm not going to
9 take that risk. Neither is third-party storage
10 holders which are -- Melissa, you brought up a
11 great point -- that's the power plants.
12 So your third-party storage holders,
13 which own about 30 or 40 percent of the storage
14 capacity in California, don't have any incentive
15 to store gas. So where does that put power
16 plants? In the day market with a lot of
17 volatility.
18 Jim, you brought up a good point.
19 Looking at those transportation slides. Why isn't
20 anybody using the south main line on El Paso? It
21 has excess capacity. The only pipeline that has
22 excess capacity to California per that chart.
23 The reason is that Permian gas is
24 selling for a 40- or 50-cent premium to SoCal
25 border. So here you are at BP. I'm going to buy,

1 I'm going to take Permian gas at $5.50; I'm going
2 to pay for transportation which is fixed on El
3 Paso, 35 cents plus fuel. And it's going to land
4 me at the California border at $6. When the
5 forward market for California border is at 5.25.
6 I can't do it.
7 And all the power projects, Mesquite 1
8 and 2, Sempra Energy Resources, their plant off
9 Baja Norte, that's 1800 megawatts. FPL Blythe,
10 another 500 megawatts. All off that south main
11 line. It's very challenging to get natural gas
12 supply.
13 So power plants don't have storage.
14 They don't want to hold transportation capacity
15 because that, over time, is a big loser. And so
16 they're all in the day market. And you have to
17 pay a premium in times of shortage.
18 And I've been to a lot of IEP meetings
19 and Jan Smutny-Jones has said a few things that I
20 laugh about. We have a faith-based energy policy.
21 We pray for snow.
22 (Laughter.)
23 MR. ALVES: And then also I heard last
24 time, last year I went -- and it's up at Lake
25 Tahoe; you really do learn something up there.

1 But, one thing is, is surplus is less expensive
2 than shortage. But it's just who pays for that
3 surplus.
4 One more point that I want to make is
5 you have the gas industry restructuring this year
6 on SoCal. It's very challenging. You have PG&E
7 unbundled; you have SoCal trying to unbundle. And
8 so SoCal core is not going to be responsible for
9 system integrity.
10 So they have a gas cost incentive
11 mechanism that the CPUC loves, and it works. But
12 if we go to this new industry restructuring,
13 they're not going to be responsible for making
14 sure that gas is flowing to California to meet
15 everybody's needs to avoid curtailments, which
16 they're very proud to say it's been 11 or 12 years
17 since we've had a curtailment.
18 So, I guess my point here is I hope that
19 the power plants and the people I market to
20 recognize that if you don't have any storage
21 you're subject to daily price volatility. And if
22 you don't have any transport, you're subject to
23 the basins volatility we've seen between the
24 basins and the border.
25 It's very challenging to provide on gas

1 demand at a discount. And that's generally what
2 they want to require. So, thanks for your time.
3 PRESIDING MEMBER BOYD: Thank you.
4 MS. JONES: Thank you.
5 PRESIDING MEMBER BOYD: Anything else,
6 Mark? I guess we've finished this subject for
7 this session. This is going to be a --
8 MR. ALVARADO: We're coming down the
9 home stretch, because we've got one more report.
10 One more staff presentation.
11 PRESIDING MEMBER BOYD: Right.
12 (Pause.)
13 PRESIDING MEMBER BOYD: Do you need a
14 break? Let's take a five-minute break.
15 (Brief recess.)
16 CHAIRMAN KEESE: We're doing a fast
17 shuffle. I just completed another meeting that I
18 had to have, and Commissioner Boyd is doing a tv
19 interview at 4:30 that he was committed to. He
20 will be back as soon as he's off camera.
21 MR. BADR: Welcome back. My name is
22 Magdy Badr. We prepared the cost of generation
23 report. I'll be very brief because we know we are
24 pressed for time, so I'll try to zip through this
25 as much as I can.

1 The purpose of the report was several
2 ones, actually. Basically the modeling unit, or
3 the modeling folks, they need to have some
4 descriptions or characterizations of the
5 technologies we are going to use in the resource
6 modeling. So this characterization is spelled out
7 in the report, and basically that's what we will
8 be using in their modeling analysis.
9 From time to time we have questions and
10 we have to provide information to the
11 Commissioners. They ask us for information about
12 how much will it cost to build a power plant, and
13 when the power plant or combined cycle, typical
14 power plant combined cycle or wind or geothermal
15 or what-have-you. So we had to prepare those
16 information to be available for them.
17 The public sometimes will call us and
18 ask for this information, as well. And basically
19 they ask the same questions. Do we have any idea
20 about how much will it cost for a particular
21 generation to be constructed.
22 Other agency, they are also calling us
23 like the Board of Equalization. They call us. Or
24 the City of San Francisco, sometimes they call us
25 for information about how much would it cost for a

1 typical power plant combined cycle, or one of the
2 renewables basically to be built.
3 Also these numbers, we feel that it
4 might help any portfolio manager to basically
5 screen out the resources, so you have basically a
6 cost, or array of costs; and now you can choose
7 between your resource options, basically.
8 So, in our work we didn't do everything
9 in the universe; we just tried to focus on the new
10 utility size power plants, those are big size.
11 And we didn't really address the DG level for the
12 small PV or biomass technology. My understanding
13 is that will be addressed in a different report.
14 The methodology we used was really
15 simple; levelized cost basically. And in
16 understanding what levelized cost is, is basically
17 it's the constant level of revenue necessary for
18 each year to recover all the expenses over the
19 life of the power plant.
20 Meaning if you put equity, as a
21 developer you put equity in, you want a return on
22 your equity, and that would be part of the stream
23 of the flow of the -- that's part of the cost
24 basically. So that's what we call cost.
25 Levelized cost for any power plant is a

1 function of, of course, fixed costs, which varies
2 annually basically. Depends on the capital, O&M
3 and fuel costs.
4 The capital costs are basically two
5 parts. Either you get to finance the power plant
6 with debts, or you got to finance it with equity,
7 or a combination between both. And most of the
8 power plants are a combination between both.
9 On the debt financing basically you
10 structure your terms basically, those are very
11 rigid, and those are bank loans most of the time.
12 And basically they are functional, loan amounts,
13 the number of years of financing and the rate, the
14 interest rate you are borrowing with.
15 Again, these are required, these
16 payments are required on monthly basis to be made,
17 or periodically. Could be quarterly or annual
18 payments or what-have-you, but most of them are
19 monthly basis.
20 Of course, before you get to that level
21 with the bank you have to do what project
22 financing require you to do, which is a lot of
23 other big set of analysis to get to the bank. And
24 the bank will agree with you. Like permits, for
25 example, and contracts and some other things.

1 On equity financing, this is different
2 because you are putting out the money out of your
3 pocket, so to speak. So you are -- and you're
4 require certain return on that equity, which
5 normally is a little higher than what you borrow
6 money with from the bank.
7 That's repaid from the residual revenue.
8 That mean you pay all your bills and you pay your
9 mortgage, so to speak, on that power plant. And
10 now you are collect the extras, that's your return
11 on your investment. And sometimes you run the
12 risk of not having anything left.
13 On the O&M costs, and those are
14 basically they run for basically labor, managers
15 and insurance and basically your typical O&M
16 costs. Those costs, they do not vary to the
17 operation mode of the power plant. If it's an
18 intermittent to peaking power plant basically.
19 They are fixed for the -- the type is not very
20 sensitive to the function of that particular power
21 plant because you still have to pay labor, you
22 have to pay managers, and you have to pay
23 insurance.
24 The variable costs that definitely
25 varies with your output. And most of the time for

1 combined cycle or for a simple cycle or a peaker
2 unit, that would be the biggest chunk or the
3 biggest component will be the fuel consumption or
4 fuel cost.
5 Additional to that would be maintenance
6 expenditures. And forced outages that would be
7 part of your variable costs most of the time.
8 Fuel costs definitely will change over
9 the time and is unpredictable, as we all know, and
10 we heard about it for the last couple days now,
11 compared to other costs of other components of the
12 variable costs.
13 We use in our analysis the forecast
14 for -- the fuel forecast, natural gas forecast,
15 from our office upstairs. And that was December
16 2002. And it seems like people like that numbers
17 for whatever reason.
18 Okay, our financial assumptions were
19 almost fixed across all the technologies we looked
20 at. We looked at 40/60 basically, or roughly
21 40/60 equity to debts. The return on the
22 investment for the equity roughly 16 percent. The
23 debt would be around 7.4 percent. And there is a
24 lot of assumptions here about that 7.4 percent.
25 Basically we are saying that the corporate has

1 good standing on their credit, and that they are
2 not having in a junk status with their bonds. And
3 they have a AAA bond and they can be -- they can
4 borrow at that lower rate.
5 Of course, if you look at the last line,
6 that's the loan or the term of the financing; it's
7 only 12 years, which most of the banks now are
8 looking at that number. And basically most of the
9 banks now, because of the uncertainty of the
10 market, they want to collect the money sooner than
11 later because later would be running the risk on
12 not recovering everything.
13 Inflation rate we used 2 percent; and
14 discount rate we used 10.8 percent. And the
15 coverage, the debt cover ratio was basically 1.5
16 percent.
17 These are the results comes out after we
18 used this method I explained, and also the
19 assumptions, these are the results. And I want to
20 point out something here. This table is available
21 in your report; however, the new things here are
22 the numbers are in bold. These are for wind,
23 hydro and some of the solar and down in the
24 geothermal.
25 The reason they are in bold because they

are different than what you have in the report. The difference is that we neglected basically in the draft report to remove some of the interconnections and the permitting costs. We left them in there in most of our spreadsheets. And you see that spreadsheet number 11. Normally for every technology you have in the appendices you will have 13 tables. Table number 11 from each one of those is the one that has the interconnections and it has the permitting. So those they have values in most of the tables, or these tables they are in bold, or technologies in bold.

What we did here, I just went in; we zeroed them out. And basically the new numbers looks like this. The final report will reflect that.

So what do we watch for as we are looking at this report? Basically a lot of things. There's a lot of things we included in our assumptions in this report. And you saw those are very much summarized in the appendices.

But other things we did not consider, for many reasons. Number one, most of these power plants are site-specific. Meaning if you will

1 build in the, you know, north California versus
2 southern California. Or if you build your power
3 plant a combined cycle or simple cycle in
4 basically an AQMD area, Air Quality Management
5 District area, it will vary a lot basically in the
6 permitting costs, as an application you will pay
7 to that District. It will vary for the way you
8 are going to site that power plant and mitigate
9 the impacts of the power plant from environmental
10 aspects like air quality emissions and cost of
11 offsets, basically, in the Bay Area will vary a
12 lot if you put that same power plant in San
13 Joaquin Valley.
14 And I'm not talking here about emissions
15 only. I'm talking about all environmental
16 aspects, meaning that perhaps water might be a
17 problem in certain area, so you would be -- the
18 city would be able to supply water to the power
19 plant. Or you have to dig your own well to pump
20 this water, for example.
21 Biological impacts could be very
22 significant if you have a big size area you are
23 putting your power plant on, and you use a big
24 land use basically; so you have to mitigate for
25 that. And also the biological impact could be a

1 severe one.
2 Also, if you have a power plant, you are
3 going to remove the existing facility, you're not
4 going to pristine land, you are going to remove
5 the existing facility and you are putting your own
6 facility. We didn't consider, for example, the
7 cost of removing that existing facility because,
8 again, that's a site-specific.
9 Infrastructures. That goes for
10 everything, transmission, gas, and waterlines,
11 basically, that's the main three ones. How close
12 are you to these things and how far are you. So
13 these costs can have a huge impact on the
14 bottomline. But, again, you cannot predict where
15 you are going to put that power plant, and you
16 have to take it by site specific.
17 So our analysis would show the bulk of
18 the information, however it doesn't show these
19 things, doesn't show these variables. Because,
20 again, it's site specific. It depends on where
21 you're going to put that power plant.
22 Once you choose to put it in area X, you
23 get to see what are the factors that can affect
24 that area. And you plug it in and now you know
25 how much it will really cost you for that plant.

1 The other thing we did consider is a
2 normal market condition, meaning that it's peace,
3 not war. In war, as we see, we heard $6 and $11
4 for natural gas versus normal prices for natural
5 gas. So there is spikes in the market during war.
6 We didn't consider that when we are analyze our
7 cost of generation over these power plants. We
8 just looked at a normal condition which is peace.
9 The other thing is we used again the CEC
10 long-term forecast. And I understand there is a
11 lot of problems. A lot of people, they are
12 criticizing that by saying well, today the price
13 is that. And our answer to that is today is a
14 short term or next month is a short term. We are
15 looking at a power plant will be built for 20 or
16 30 years, so the long-term forecast is more
17 important in this aspect.
18 Also what we did consider is the
19 corporate credit status. We assumed that they are
20 AAA bond status; the credit is reliable by Fitch,
21 S&P and Moody. They told us that, yes, these
22 corporations are in a good status; they are AAA
23 bond.
24 The reason for that is it's very
25 important because their borrowing power will

increase as you having good credit. If you have bad credit, perhaps the debt ratio will change on you. And instead of 40/60, perhaps you go to 50/50 or the opposite, 60/40. Depends on the banks and how much they will trust you and how much credibility you have on your financial statements.

Also interest rate might go shoot up on you; instead of 7.4 and when you have bad credit, it might go up over the 10 percent, for example. That's a huge impact on the mortgage or the payment you have to pay every month or every period to your bank. So that's have huge impact on that.

The other thing we did not consider is the hedging for natural gas; the hedging costs for natural gas. And the price volatilities are not counted for. And the reason, there's two ways to hedge, either physical hedge or financial hedge. And we haven't considered either one of those in our analysis. So this is, it could have a big impact on the gas-fired technologies like combined cycle and simple cycle.

This is basically a word of caution. These numbers are not alone, by themselves,

1 sufficient to choose between technologies.
2 Meaning if you look at the table I presented with
3 all the answers, say well, I want to put a
4 portfolio, pick up the cheap one. That's not, by
5 itself, going to help you to have a very good
6 portfolio.
7 Because the choice should depend on the
8 resource system portfolio, and the performance of
9 the resource, itself. And meaning that do you
10 need capacity more in your system versus do you
11 need energy, more energy in your system than you
12 have in capacity, for example.
13 So you have, as a portfolio manager, you
14 have to see what you really need in your portfolio
15 to put in, versus okay, this is the cheapest one,
16 and I'm going along with the cheapest resource in
17 general.
18 Another way of explaining what I'm
19 trying to say here is if you have two resources,
20 they are 30 cents a kilowatt hour, for example.
21 One of them is can provide you capacity and
22 energy; the other one can provide only energy.
23 Which one will you choose? And the answer is it
24 depends on what I need to put in my portfolio; is
25 not that I need that one or that one, by itself.

If you look at reliability, you have to look at the resource. If you wanted to look at energy by itself, so that's what you need to be looking for.

These are the workshop questions. I hope I just went through them very quickly here through my presentation, basically. And I believe we have two people who wanted to have presentations before you. I believe Bill Marcus and Mark, and I'll ask Bill Marcus to come first because he asked us to do so, so he can leave. He has an appointment.

MR. MARCUS: I'm afraid I'm still back in the level of old technology here.

MS. JONES: It's more dependable, huh?

MR. MARCUS: Certainly less efficient. Particularly when I was out there printing these things up on transparencies at 2:15 this afternoon.

I think this will work. I'm Bill Marcus; I'm representing TURN this afternoon. And the reason I'm here is that not because we're thrilled with high electricity prices, by any means, but that if we're going to have them we need to plan for them and understand them and

1 build the right portfolios to deal with them.
2 And we have a set of overall concerns.
3 I think our first one is that these numbers, taken
4 out of context, and I'm very happy to hear the
5 staff's levels of caveats they're putting on these
6 numbers, but these numbers, taken out of context,
7 could be used as the benchmark for a renewable
8 portfolio standard and we just don't think they're
9 ready for prime time for that, for that purpose.
10 They could be used to make suboptimal
11 policy decisions, and in particular we had
12 concerns about the two technologies we looked at
13 in the most detail, which were wind and combined
14 cycle.
15 And I think I'm going to hit -- after
16 talking to staff I understand a little bit more
17 about what is going on here, that they've been
18 trying to take some of these development, land
19 acquisition and permitting costs out of their
20 analysis. Might be better to put them into all
21 sides of the analysis. But they made the decision
22 to take them out, but they managed not to take
23 them out of the wind project where they represent
24 something like $5 a megwatt hour of the windmill's
25 costs.

We also see that the cost of emissions offsets are missing. That's a site-specific element, but it doesn't make it any less real.

MS. BAKKER: Well, let me check, Madgy, the reason you wanted to take them out is because they're costs, site-specific, and therefore you would factor them in -- one would factor them in on a site-specific basis. And wouldn't that also be true for wind?

MR. MARCUS: I think there are a set of costs that would be factored in on the site-specific basis. Again, if we're moving towards something like a renewable portfolio benchmark we may have to take some kind of average of them, rather than saying they're zero. Because the windmill meeting the benchmark will obviously face whatever their site-specific costs are.

MS. BAKKER: But if you were going to do a level playing field you'd pretty much have to do the same then with the thermal power plant or --

MR. MARCUS: Yeah, I think that's true. And the other issue that came up, looking at these numbers, is that the staff numbers are dry cooling. And I know that it's been a very contentious issue --

1 MS. BAKKER: Are wet cooling.

2 MR. MARCUS: I mean wet cooling.

3 MS. BAKKER: Yeah.

4 MR. MARCUS: And there's a very -- it's

5 been a very contentious issue in a number of

6 siting cases for this Commission, so I thought I'd

7 better flag it for you that the base numbers you

8 have here have made a technological determination

9 that, you know, clearly in siting cases you guys

10 are going to be looking at it on a case-by-case

11 basis, and that dry cooling has some additional

12 capital cost, and has other issues of lower output

13 and efficiency.

14 MS. BAKKER: But lower water costs.

15 MR. MARCUS: But then they have lower

16 water costs, but it's not at all clear where the

17 water costs are in the staff analysis.

18 Looking at O&M and other expenses, I

19 think the overall concern that we have with the

20 O&M is the $30 per kW per year looks low.

21 Particularly when $13 of it is the amortization of

22 an overhaul.

23 They basically say other than insurance,

24 labor and that overhaul, it's going to cost them

25 only $4 per kW to run the plant. We think that

1 number is light.

2 SCR operations costs look like a generic

3 plug to us, and a possibly fairly inexpensive one.

4 Pretty low costs, they used identical numbers for

5 combined cycle and a combustion turbine in total

6 dollars, even though there's a fivefold difference

7 in megawatts and probably a threefold difference

8 in combustion turbine megawatts.

9 I put an Edison comparison down here. I

10 recognize that it's a little bit apples and

11 oranges, but I think the difference is not between

12 a dollar and a penny; I think the difference is

13 probably -- the truth lies somewhere in the middle

14 with the SCR operating cost of a gas turbine.

15 It's likely that you'll need to replace

16 the catalyst at sometime in the life of the plant.

17 And in addition the staff model has no capital

18 additions for any power plants. Capital

19 additions, large items that have to be maintained.

20 And there's no inventory of either fuel or spare

21 parts in any of this analysis.

22 Heat rate numbers that are given, we

23 have a concern with. Basically we agree with the

24 staff that 6800 or a number like that is probably

25 what one of these plants can do under the absolute

1 best conditions, running flat out, just after it's
2 been done with an overhaul and at moderate
3 temperature.
4 But there's some real world elements
5 that we're concerned about which would cause the
6 actual performance of the plant, even if it's in a
7 baseload mode, and not as a cycling plant, would
8 likely be worse; including startups and ramp-up
9 costs, partial forced outages, degradation on hot
10 days, things of this sort that we've listed here.
11 And we would think that probably a number closer
12 to between 7300 and 7500 Btus per kilowatt hour
13 would be a better representation of actual
14 performance under baseload conditions, but real
15 world baseload conditions.
16 MS. BAKKER: Let me get a clarification
17 again from Magdy here now. It strikes me that
18 were you to model a combined cycle you would
19 reflect at least some of these operating
20 characteristics in the simulation in which one of
21 these generators was added.
22 MR. BADR: Right.
23 MS. BAKKER: Is that right? So, we
24 might be able to actually verify that in real life
25 a plant would have a higher heat rate on average?

1 MR. BADR: On average, that's correct.
2 But the way we tried to do this is as we said
3 here, as Bill mentioned, that the 6800 is --
4 MS. BAKKER: Full load.
5 MR. BADR: That's full load, running all
6 the time. And even when you ramp it from 70 to 90
7 percent capacity or something, that is still fine.
8 But he's --
9 MS. BAKKER: Right, but all I'm saying
10 is that --
11 MR. BADR: -- talking about
12 circumstances where --
13 MS. BAKKER: -- you've used an input
14 assumption. You've just said, okay, we're going
15 to say full load heat rate. And what he's saying
16 is in real life, which doesn't fit on the table
17 very well, it's going to operate in various stages
18 of load from zero to full load and in between
19 some. And that the heat rate degradation from
20 that would be shown in a system simulation. But
21 you're using an input assumption to fill out your
22 table that says full load heat rate.
23 MR. BADR: That's correct.
24 MR. MARCUS: And I think that the
25 difference that we have is that if we were using

1 an input assumption to fill out a table like
2 Magdy's for purposes of calculating, for example,
3 a renewable portfolio standard benchmark --
4 MS. BAKKER: Right, right.
5 MR. MARCUS: -- you would probably be
6 using a different number that would be -- it might
7 be reflecting baseload use rather than lots and
8 lots of cycling, but it would reflect the kinds of
9 factors that are on this page.
10 MS. BAKKER: Sure, sure. It does get
11 forced out and therefore it does have to ramp back
12 up, and --
13 MR. MARCUS: Yeah, so I think that's the
14 difference there.
15 I am going to show you the slide that
16 shows $11 gas prices today provide a lesson. And
17 by the way, the lesson is you're better off here
18 than in New York City where it's 25.
19 MS. BAKKER: Yeah.
20 (Laughter.)
21 MR. MARCUS: But seriously, I'm not
22 telling you that necessarily the forecast is bad.
23 You've heard some criticism of your gas price
24 forecast from Rich Ferguson. I'm not going to
25 repeat any of what he said.

1 But what I do want to point out is that
2 a forecast and certainty are different things; and
3 it costs somewhere in the vicinity of half a penny
4 a kilowatt hour to get certainty out of one of
5 these analyses.
6 We've put down on this slide several
7 examples of data sources for trying to calculate
8 what this number is. I will tell my friends at
9 Edison that I did not use confidential data to
10 come up with it. I backed into it using public
11 information.
12 (Laughter.)
13 UNIDENTIFIED SPEAKER: Where did that 80
14 cents come from --
15 MR. MARCUS: They had an application
16 filed before the PUC to hedge, to spend $208
17 million to hedge gas prices for about a two-year
18 period, and it was to hedge their QF generation.
19 UNIDENTIFIED SPEAKER: (inaudible).
20 MR. MARCUS: And they do change from
21 time to time; I'm not -- I've got a couple of
22 slides on wind. This one is simply saying, well,
23 gee, we've had quite a few windmills coming in at
24 a lot less than 5.4 cents for the California Power
25 Authority and San Diego Gas and Electric's recent

1 solicitation.

2 And my last piece of paper is mainly

3 about some of the permitting development and

4 financing costs. I do think there are problems

5 with including these pre-development costs in wind

6 and not in other technologies.

7 I think that the pre-development costs

8 may be inconsistent with the assumption that

9 you're looking at fully credit worthy entities

10 that stand on their own and finance on their own,

11 because there's an awful lot of equity and debt

12 costs that look a lot like partnership structures,

13 and things of that sort in the numbers.

14 And I also noted that the interest

15 during construction was double counted in the

16 staff's model there.

17 And this is a big issue because this set

18 of costs on this slide that I'm complaining a

19 little bit about are about $5 a megawatt hour when

20 run back through the staff's model in approximate

21 terms.

22 And I think with that I will stop and

23 take any questions that anybody has.

24 MS. BAKKER: I have one question about

25 your next-to-the-last bullet under -- no, the

next-to-the-last slide. I'm pretty sure I know the answer to the second bullet, but the first one I'm not so sure.

Would wind bid low because they were getting an Energy Commission -- had won an Energy Commission auction and therefore were getting 1.5 cents or something like that?

MR. MARCUS: I think some of the smallest projects, I mean some of the lowest cost projects would be in that mode. There's a range of project costs between somewhere below 4 up to somewhere above 5. And I would say at the bottom end of that range you're probably right.

MS. BAKKER: Okay.

MR. MARCUS: You know, looking at the -- but the median number was somewhat below 5, and I was thinking more from the median than, you know, just looking at the range.

MS. BAKKER: Okay. Now, but for the San Diego ones, isn't it true that if they bid below the price they're not eligible for --

MR. MARCUS: That's in fact -- the benchmark there was 5.37 cents. And anything under that number would not be eligible.

MS. BAKKER: That's what I thought.

1 Okay. Thank you.

2 MR. BADR: For the benefit of the

3 Committee and everybody else in the audience, Bill

4 talks about the difference between dry cooling and

5 wet cooling, and we consider wet cooling versus

6 dry cooling.

7 The difference in capital cost is really

8 significant, $25- to $30 million. Yes, there is a

9 lot of people came before this Commission and they

10 requested, or they ask at this Commission to site

11 power plants with a dry cooling. But they weren't

12 very successful most of the time.

13 I know of one or two, maybe three power

14 plants they have dry cooling on them, like Sutter

15 Power Plant, for example. And that was for very

16 significant and very specific problems they have

17 around the power plant.

18 So, not every power plant will be built

19 a combined cycle or simple cycle, the developer

20 will put on it or will install dry cooling just

21 because it's better. The economics sometimes play

22 a big huge factor in the capital costs, and if

23 they can stay away from it they will.

24 If you look at how many power plants

25 they've been sited with this Commission and how

many of them have dry cooling, you will see that we're betting off considering the wet cooling technology versus the dry cooling, when we try to estimate this technology cost.

MS. BAKKER: Well, let me ask you a question there, because first of all, it seems to me that if you're predicting far into the future you could be looking at circumstances where water becomes progressively more of a challenge to California. And so, over time, it could certainly be the case that more and more of the new permitted facilities would face the challenge of better uses of water than cooling power plants.

So it strikes me that when you're predicting the future you do have to worry about whether that is a progressively more likely.

I don't know the answer to that. I'm just saying that when you're predicting the future, that's certainly a factor you need to keep in consideration.

The other thing is that some of these things where there are uncertainties, we deal with it by trying to put a fudge factor in there to deal with the fact that there's some probability of an additional charge. And maybe there's some

way we could capture things like that. It's just an idea.

MR. BADR: You're absolutely correct. But, again, I have to go to the site specific.

MS. BAKKER: Right, exactly.

MR. BADR: Sutter, for example I know that very well, because I sited that power plant. They have a problem with the discharge water, and that will perhaps destroy some of the levees and they have causing problems to the farmers around it.

So the Commission Staff asked them to put a dry cooling on that particular power plant because of the discharge problem. And also the dry cooling is not going to solve the problem. You circulate water in the dry cooling a whole lot more than wet cooling, and therefore you concentrate toxics inside this water.

So you either have to clean it up before you discharge it, or you have to just discharge it somewhere where you don't care about the toxics in this water.

So, it's not, you know, dry cooling doesn't fit every -- again, it's site specific, I guess, that's my best description to that. It's

1 not you can say this is better than that one. Or
2 we prefer this one over that one because of the
3 aqueduct or the water usage in California.
4 Again, could be an area where they use
5 marine water all together. So we don't know where
6 the power plant is going to be, but just by making
7 the assumption on a specific cases, and use that
8 as a general case, I don't think you'll agree -- I
9 think you will agree with me that's not really
10 kosher to do so.
11 MR. McCANN: This is Richard McCann with
12 M-Cubed, and I worked on developing this model. I
13 also just recently was working with the staff on
14 the SMUD Cosumnes project on the FSA on reclaimed
15 water use.
16 I mean most cases these power plants it
17 is much cheaper even to use reclaimed water at a
18 much higher cost than potable water than putting
19 in dry cooling. And dry cooling is an option
20 that's really, from an economic standpoint, and
21 from a water conservation standpoint, really only
22 viable in a case where you have, it is extremely
23 expensive to bring water into a particular
24 location, or they have a water discharge problem.
25 I mean if you don't have those two

1 problems, using reclaimed water is still cheaper
2 than going to dry cooling. And in that case, you
3 are not impinging on the state's water supply.
4 MR. ALVARADO: I think a lot of the
5 points that you made, Bill, are valid. And I do
6 think we want to sort of examine it, maybe look at
7 other additional hedging costs. We may need to
8 consider like to address the heat rate value
9 questions and things like that.
10 So, I guess with Magdy's concurrence, I
11 think we will try to examine some of these
12 features a little bit further. Probably adding
13 some hedging factors into the numbers.
14 MR. BADR: Most definitely. The hedging
15 factor is one of the important factors that I
16 pointed out in my caveats and definitely we need
17 to look at that. And what was it --
18 CHAIRMAN KEESE: You don't look at tax
19 credits, either? You haven't wrapped tax credits
20 into the --
21 MR. McCANN: Tax credits are for each of
22 the technologies that are available are included
23 in the analysis.
24 CHAIRMAN KEESE: So wind would be --
25 MR. McCANN: Whatever federal tax

1 credits are available to wind are included in the
2 cost estimates.
3 CHAIRMAN KEESE: Okay, so 5.42 is a net?
4 MR. McCANN: Right, net of those
5 credits.
6 CHAIRMAN KEESE: Net of wind. It might
7 be 6, I forget what the --
8 MR. McCANN: Yeah, it turns out that
9 wind doesn't get many tax credits because the
10 federal tax credits are over-subscribed and they
11 allocate them.
12 MS. BAKKER: I'm still confused about
13 the site-specific costs. I heard what you said
14 was that you were taking them out because they
15 were too site specific. And yet --
16 CHAIRMAN KEESE: Too variable.
17 MS. BAKKER: Yeah, too variable, and yet
18 you put a power plant in a resource plan, it has
19 development costs. What are you going to use?
20 MR. BADR: Oh, no, we did use the
21 development costs. This is -- you have the
22 capital costs in there; you have the O&M in there;
23 you have the variable costs there. You have all
24 the costs you need to establish that -- to build
25 that power plant.

1 But what you don't have in there is the
2 cost of the application for permit; you going to
3 have the cost of the emissions associated with
4 that power plant to get out, because mitigation --
5 MS. BAKKER: I followed what he was
6 laying out there, and that's what I'm asking you.
7 How are we going to deal with that? Pretend that
8 those costs aren't there?
9 MR. McCANN: Well, let me answer one
10 real quick question about this is that in this
11 project, in the way that the costs were developed
12 was actually for the renewable technologies it was
13 a survey of different project developers, or
14 people who were very familiar with their specific
15 technologies of how the costs were put together
16 for their projects.
17 They did not supply information all in
18 the same format because they all thought about
19 this differently. And so that what you would do,
20 would get back is, for example, what happened with
21 wind is they gave back a very detailed description
22 of what their various costs were.
23 Geothermal was the same way. What we
24 found in the solar was that there was less detail
25 that was provided. Fuel cells even less detail.

1 So that when you look through it you will see that
2 the list of items that are included are different
3 for each one of the technologies for that reason.
4 Combined cycle, actually what we did is
5 we used a number that the staff has been using for
6 a number of years to estimate the cost of combined
7 cycle. And I actually don't know this for sure,
8 but my understanding was was that that actually
9 included some development costs. But it was
10 essentially a single number. It did not have the
11 items broken out like it does for wind, where it
12 has the land acquisition cost and all of those
13 other components that are included.
14 So, there's less detail in that aspect.
15 One of the things that we need to revisit is going
16 back and breaking, finding out what we need to
17 break out and exclude.
18 MS. BAKKER: Yeah, the first thing we
19 need to know is if we have the problem, I guess.
20 MR. McCANN: Right. And the thing is
21 looking at the costs that are in the AFCs where
22 they do report them, are in very close to the
23 range of costs that we have here in this model.
24 So that it's not as though the -- unless the AFCs
25 are excluding some of those other costs that we're

not aware of, we are including most of the costs the developers are reporting in the AFCs.

MS. BAKKER: Okay.

MR. MINICK: Mark Minick, Southern California Edison. I apologize that I don't have a presentation to make, but I'm working seven-hour days trying to put together a resource plan for April 1st.

So I have just a few comments and this is one of the rare times -- and Bill and I have been adversaries for many many years -- that I'm going to agree with many of the things that Bill said.

First off, regarding your capital costs, I truly don't believe that you have included things like interconnection costs, transmission lines, gas pipelines, other outside costs, makeup water, precommercial owned and permitting emission offsets and things like that.

So we have a significant difference in what we think the costs are and what you think the costs are.

We also think your capacity factor for a CCGT is extremely high. And under the current conditions in California a unit would not operate

at 91.6 percent. We think something more like 75 percent is much more realistic.

You also show no starts of the unit through the entire year. That's totally unrealistic. The unit is going to have starts, especially when it can't sell all hours or it has forced outages and things like that. So we think 50 starts for that unit would be more realistic.

In regard to the O&M costs I disagree with Bill. I think that $30 is actually too high. So we can send you what these assumptions are in an email after I get down from here.

Regarding your forced outage rates for that particular unit we think they're quite a bit too high at 4.6 percent. We think 1 percent forced outage rate for combined cycle technology would be substantiated by data that you can get out of various literatures and sources, and we'd be glad to back that up.

MR. McCANN: Yeah, that number came from the AFCs.

MR. MINICK: Okay, well, that's just simply too high based on FERC form 1 data and things like that.

As far as one issue that we have

1 difficulty with is duct firing. I think you'll
2 find in your AFCs that almost every facility
3 that's going in has duct firing. Duct firing is
4 supplemental firing of gas in the steam section of
5 the unit to give you more megawatts. Anywhere
6 from 40 megawatts to 80 megawatts is typically
7 what the duct firing will give you. It's very low
8 cost, incremental capacity and at times of high
9 temperatures and other reasons you can use duct
10 firing to get your full output. So to get the
11 output of your unit up produces less than what we
12 anticipate. I think you should look at duct
13 firing.
14 As far as your heat rate, I'm sort of
15 between the two. 6800 is a heat rate that the
16 manufacturers say is good for ISO conditions; and
17 Bill says 73 to 75 is what it should be. We're
18 around 7150. The reason we're at 7150 is because
19 we looked at the unit in more of a typical
20 application in California.
21 I'll back that up with you can look at
22 the contracts for Magnolia and other resources
23 that PG&E is making to people. They're
24 guaranteeing 7300. So, I'm assuming they can do
25 better than that, because they're putting that in

their contract. But I don't think it's as good as 6800. I think that's ISO conditions.

As far as your startup fuel, you seem to have the same startup fuel for both CCGTs and gas turbines. One is more a four-hour state and one is possibly a 30-minute or less start, 10-minute start. It shouldn't be 10,000 MmBtus. It should be closer to about 2000 MmBtus for a CCGT and maybe 200 Btus for a combustion turbine.

Also the number of starts you have for your GT or your gas turbine is zero. Again, we think they are peakers, they'll be used for short periods of time on many days. And that's an error on your part.

Also your forced outage rate is .5 percent. Unless they've gotten a whole lot better, I haven't seen many GTs that have .5 percent forced outage rate. We think 5 percent is probably more realistic. It might be a little high, but we think .5 percent is too low.

Your heat rate for your GT is optimistic at 9300. Typically the big difference we have there is you've assumed an LM6000 for your peaker. We're assuming that you might build a Frame 7 for a peaker. So we'll have to resolve that

1 difference. You might look at two kinds of
2 peaking facilities. It's cheaper to build a Frame
3 7. So like the Sunrise project before put on the
4 waste heat boiler for shorter duration operations
5 than an LM6000.
6 Therefore, and it's cheaper on an
7 overall capital basis. But that's a little higher
8 heat rate. Those things are the kind of things
9 you're going to have to work out.
10 Let's see, what else do they have real
11 quick here. Some of your costs, I think, are a
12 little high or a little low for your expenses for
13 personnel at the site. The $80,000 was good a few
14 years ago, but these kind of plant managers now
15 are in high demand; we think $120,000 is a better
16 cost.
17 MR. McCANN: Are they really still in
18 high demand?
19 MR. MINICK: They're still in high
20 demand.
21 (Laughter.)
22 MR. McCANN: Given Calpine's turbine
23 cancellation?
24 MR. MINICK: Well, they haven't built
25 all those plants yet, okay. So we think some of

1 those costs are just a little bit low. And it
2 isn't a big deal. And we'd be glad to send you
3 what we think the costs should be.
4 Your natural gas price, I won't go into
5 it. It's probably reasonable.
6 And some of the other salaries might be
7 a little bit on the low side.
8 We also wanted to note that you put down
9 the number of personnel for what looks like a
10 single block, sort of let's say a 500 megawatt
11 CCGT block. That's probably pretty close to
12 right. As you build additional blocks of a
13 station you wouldn't necessarily take that 23
14 people and --
15 MR. McCANN: Right, and this is only a
16 500 megawatt block.
17 MR. MINICK: -- cookie-cutter. Right.
18 MR. McCANN: I mean this is the problem
19 with the site specific, you know, --
20 MR. MINICK: Right. But I think if
21 people wanted to look at it, if you build a 1000
22 megawatt block or a 2000 megawatt block, because
23 many sites you could do that over time, that the
24 costs might go down because of additional savings
25 in personnel and things like that.

MR. McCANN: Right.

MR. MINICK: Let's see, another issue not on CCGTs, I think you should use a 50-year life or a 60-year life for hydro facilities.

MR. McCANN: Yeah, that's a question of how long do you -- the economic life versus the physical life of the facility, and the amount of time that you'd expect to recover the costs.

Because, for example, the utilities carried those as 40-year lives in their books.

MR. MINICK: We used to use 50 or 60, and I think federal relicensing is every 50 years. So I think you build it for a 50-year life, and then you sort of realize it's --

MR. McCANN: Right, well, I know that PG&E carried them in a 40-year life.

MR. MINICK: Okay, I think Edison does 50, but -- so maybe 40 or 50, either one would be better than the 30 --

MR. McCANN: Right, well, this is -- the other problem is who's building the hydro plant.

MR. MINICK: True.

MR. McCANN: So, to a large extent the hydro plant, since there are no hydro sites really available, --

1 MR. MINICK: Right.

2 MR. McCANN: -- it's almost like a plug

3 that's there. There's, you know, probably maybe

4 another 300 megawatts of hydro that's available in

5 this state.

6 MR. MINICK: Just, I'm looking for your

7 credibility.

8 (Laughter.)

9 MR. MINICK: Make it 50 years and make

10 everybody happy. I don't think it will change the

11 end result that much.

12 Again, on wind, my concern isn't the

13 cost necessarily of the wind; I've been at Edison

14 28 years, many years in planning, some years in

15 operations. I'll be flat-out honest, wind energy

16 is probably economic. You can't run the system on

17 all wind. The operability problems are extreme.

18 And you haven't put any costs in there

19 about how you cover winds going the wrong

20 direction when you want to ramp, okay. You have

21 to back it up with some other resources. I don't

22 know whether you want to penalize wind for that,

23 or just recognize it in writing. But wind doesn't

24 necessarily meet your operability concerns.

25 And no disrespect to the CPUC, wind

isn't always there at the time of the peak. When you put in 1000 megawatts of wind, he'll stay that 250's there at the time of the peak, whatever; I'll say that it's 100. It's something less than 1000, okay.

So you have to realize your can't, even if it was economic, and you could 10,000 megawatts of wind, you can't run your system on all wind. And that needs to be recognized.

And that's sort of a quick summary. And I'll answer questions if you have any.

MR. BADR: Actually I have one question about your peaker LM6000 versus the Frame 7. I appreciate what you're saying, but we found that a lot of developers, especially peakers, they would like to have the LM6000 because they can build on it, like they will have a block right now, the peaking capacity sometimes is not all called on.

Like if you have a Frame 7F, you might have 170 megawatt available on peaking. But normally you will get maybe 50. You want to have 50 megawatts right now. So they build incremental the LM6000 of 50 megawatt, each three of them next to each other, for the same amount, 150 or 170 megawatt. So they can fire up one at a time and

1 become cost effective for them instead of firing a
2 big engine and they will not be cost effective for
3 them if they don't use it, the whole capacity, 170
4 or 180 megawatt.
5 So they choose to use the LM6000, I
6 think that's the rationale for it.
7 MR. MINICK: Right. And my discussion
8 about that is that California's a 50,000 megawatt
9 system. When you lose a 500 megawatt or a 1000
10 megawatt, you don't have to replace it. You can
11 easily absorb 170 megawatts. If it's a little
12 tiny utility, I agree.
13 But now I'll argue it on your side.
14 Right now the emission standards for LM6000s are
15 in the state at 2 parts per million. And LM6000
16 can easily make that. There's some discussion
17 that a Frame 7, by itself, can't make that
18 emission standard.
19 So I can see both sides of the issue.
20 You might want to put both in again, with some of
21 the caveats that there might be an emission issue
22 with the Frame 7 unit. I'm not saying the LM6000s
23 are wrong --
24 MR. BADR: Right.
25 MR. MINICK: -- I'm saying -- we're

1 pretty big, I mean Edison could probably absorb
2 170 megawatts at one particular --
3 MR. BADR: Right.
4 MR. McCANN: Right, but actually we're
5 looking at this from a merchant developer
6 standpoint. To them the loss of a big unit, given
7 their contracts, is -- their financial situation,
8 they're like a small utility.
9 MR. MINICK: Yeah, but have to sort of
10 weigh both. It is quite a bit cheaper to build a
11 Frame 7 than it is for a bunch of LM6000s on the
12 economic standpoint, cost per kilowatt installed.
13 MR. McCANN: Right.
14 MR. MINICK: I haven't said which one's
15 better yet, I'm just saying it's different
16 applications. You kind of have to use one to the
17 other.
18 MR. McCANN: And you'll notice the
19 economic assumptions that are in here are for
20 merchant developers, not for IOUs.
21 MR. MINICK: I thank you for your
22 preliminary analysis. Again, I'm just getting
23 back into resource planning. Edison has just
24 formed a resource planning group. I did it for 12
25 years, and that was 12 years ago. I'm back again.

1 MR. BADR: Can we get your comments in
2 writing?
3 MR. MINICK: Yes, I will send my
4 comments to you in writing.
5 MR. BADR: Very good, thank you.
6 Actually -- okay, go ahead. We have another
7 presentation, that's why. But --
8 MR. HATTON: Do you want to go first,
9 or --
10 MR. BADR: Oh, go ahead.
11 MR. HATTON: Okay. My name is Curt
12 Hatton and I'm representing Pacific Gas and
13 Electric today. PG&E first would like to applaud
14 the CEC Staff on developing a comprehensive list
15 of the cost structures of both renewable and
16 thermal power generation resources. Clearly a lot
17 of work went into the report that you guys have
18 put out.
19 MR. BADR: However --
20 (Laughter.)
21 MR. HATTON: However, PG&E has a couple
22 of observations and suggested changes regarding
23 your preliminary report.
24 First I'd like to say that the most
25 meaningful, overall cost comparisons occur when

1 all significant cost components are included
2 across all technologies.
3 Originally I was concerned with the fact
4 that permitting interconnection costs had appeared
5 to have been included for a majority of the
6 technologies, but not necessarily all. In your
7 presentation today you indicated that at least
8 some site-specific costs were going to be excluded
9 from all of the resources.
10 I think it's important that you try to
11 develop some sort of proxy cost or average cost
12 that you can put in there to try to capture what
13 the cost differentials are between particular
14 types of resources.
15 And I think it's important to include
16 all costs including permitting, interconnection,
17 infrastructure, their gas infrastructure or
18 transmission infrastructure costs, or/and
19 including environmental costs.
20 It may also make some sense to compare
21 some of the individual cost components across
22 technologies to see if they make sense. For
23 example, land costs varied from I think $1000 an
24 acre to $100,000 an acre. I think some of --
25 MR. McCANN: Yeah, that had to do with

1 rural versus urban settings.
2 MR. BADR: Right.
3 MR. HATTON: Right, but I saw at least
4 four or five different costs for various land
5 costs, and you know, you might have a rural cost
6 and an urban cost, but I think you might have just
7 two costs rather than three or four different
8 costs.
9 You know, as SCE indicated, there's some
10 of the CT starts, had indicated were zero. I
11 thought this was a little bit unrealistic to the
12 extent that CTs were going to be for peaking type
13 activities. I think they would have some starts
14 during the year.
15 Another issue is the long-term gas price
16 escalation post-2013. It looks like you base it
17 upon the escalation that occurred between 2012 and
18 2013. I would suggest rather than using a single
19 year and then escalating at that year's escalation
20 rate for the remainder of the study period to use
21 some sort of trend. Maybe use the last five years
22 or last three years, but try to take not
23 necessarily the last year and then extend that out
24 into the future.
25 I think that's most of the important

1 points. Thank you.

2 MR. BADR: Thank you.

3 CHAIRMAN KEESE: Thank you.

4 MR. BADR: I would like to get Duke

5 Solar to do their presentation. Mark from Duke

6 Solar.

7 MR. SKOWRONSKI: I'd like to take this

8 opportunity to thank the Commission Staff for the

9 time to present this. Essentially what I'd like

10 to do is present a new technology that wasn't

11 covered in the CEC report.

12 I'm an employee of Duke, but I'm here

13 representing two companies, both Duke and Inland

14 Energy. And I got a slide to introduce each

15 company, and then get into a description of a new

16 technology.

17 Duke Solar. Duke, the regulated

18 utility, spun off Duke Engineering Services, and

19 Duke Engineering Services spun off Duke Solar. So

20 we have the name Duke, but we're no longer

21 associated with either.

22 We have three business divisions in

23 power gen, building, solar water heating and space

24 heating. Most of our work is international.

25 Water and space heating actually pretty big time

in South America.

We recently signed a 50 megawatt SEGS type unit with the Nevada, Nevada power company, Sierra Pacific. And also we recently signed a 1 megawatt organic ring -- cycle contract with APS that we hope will be expanded to about 25 megawatts.

Inland Energy was formed in 1989. In 1992 they took on the development of the High Desert Power Plant. This is an 830 megawatt project that comes online I believe in April, a couple months ahead of schedule.

Inland developed it for about six or seven years, securing the permits, the rights-of-way, the land, permits and everything. And they sold most of the position to Constellation Energy Group, who is now basically the builder and owner of 830 megawatts.

Inland and Duke bring together very specific expertise, and we're marrying them into a solar combined cycle project. And before I get into the description of the combined cycle, we'd like to point out that we think that the CEC report might be a little bit out of date with respect to the costs presented.

1 There's an independent report, Sargent
2 and Lundy. I don't have a website, but I brought
3 a hard copy for you, Magdy, that you can have.
4 And also another report, Pathway for Sustained
5 Commercial Deployment of Solar-Thermal
6 Technologies. You can access that on the web at
7 the address shown.
8 Both these reports show solar thermal
9 would be in the 8 to 10 cent range. And, by the
10 way, the report, Pathway for Sustained Commercial
11 Deployment, CEC was an active participant in that
12 report. That report's about three years old.
13 And both of the reports, however, do not
14 reflect, neither does the CEC report, reflect the
15 cost of a hybridized plant.
16 Basically we think the hybridized solar
17 plant combined with the combined cycle gives you
18 the best of both worlds. We have load following,
19 combined cycle generation with solar component.
20 It offers an onpeak green generation with high
21 reliability, due to the combined cycle backup,
22 basically you can look at the plant as 24/7
23 because of the combined cycle component.
24 The levelized solar power cost is
25 reduced. And this is because we have higher solar

efficiencies when we integrate the solar ring -- cycle in with combined cycle there's certain synergies on the energy efficiency. We get economies of scale. A 200 megawatt steam turbine would have an average cost per kilowatt significantly lower than a 50 megawatt solar stand-alone steam cycle. And there's also commonality of infrastructure for transmission, substation, staff, maintenance buildings, things of this nature.

And in addition, since about 10 percent of the capacity would be solar, no matter what, emissions you have from combined cycle will always be 10 percent less than the competition, because 10 percent of this is going to be solar.

Basically for any engineers left in the audience, this is the cycle that we're proposing. You can go through it, but this was taken from the ASME 2001 forum. This was a study that tried to optimize, maximize the use of the solar fraction into a combined cycle.

We have two sites. One is Harper Lake, which is a two square miles parcel. It actually was to be the continuation of SEGS X, XI and XII. We have 10,000 acrefeet of water, and we're

1 looking at making this into some sort of an energy
2 renewable park with biogas burning cow manure and
3 also solar.
4 We have transmission; might have to be
5 upgraded. We have access to three gaslines which
6 would augment the solar plant.
7 This is a view of an existing power
8 plant. This is the High Desert Power Plant that's
9 coming online in a couple months; 830 megawatts.
10 And if I can draw your attention to the top part,
11 right in this area here, we're looking at putting
12 in High Desert Power Plant Number Two. This is
13 the one that will be solar hybridized.
14 The site is already, quote, sullied, if
15 you will, so we think we can piggyback on
16 permitting, and the transmission, the water rights
17 and everything that have already been negotiated.
18 And, again, Inland Energy is the primary developer
19 of this proposed power plant. And Duke is
20 partnering to provide 50 megawatts of solar
21 fraction.
22 This plant, by the way, will be scaled
23 down. The High Desert Power Plant Number One is
24 830 megawatts. And we're looking at about 450,
25 two Frame 7's, hybridized with 50 megawatt solar

1 component which would give you approximately 500
2 megawatts total.
3 Southern California high desert, it's a
4 premiere area for solar thermal. Inrale
5 (phonetic) has categorized various sites in the
6 United States, and this is one of the top rated
7 sites. And it's high altitude, relatively high
8 altitude, about 2500 feet. This reduces the haze
9 and the scatter.
10 Solar thermal is a little bit different
11 from PV, in that we need direct normal insulation,
12 direct normal sunlight. And it's got a little bit
13 of dust or aerosols or whatever that scatters the
14 radiation and you can't focus it. So, we like to
15 have it fairly high up, and the desert is a
16 perfect area for that.
17 Low-cost land; it's got infrastructure,
18 gas, water. Transmission may need upgrading. DWP
19 has some space in their line; we're working with
20 them on that.
21 High insulation obviously. Minimal
22 number of cloudy days. And we have an existing
23 site to piggyback permitting.
24 My take-aways here is that solar
25 provides competitive green energy. In lieu of

1 Duke as a manufacturer and proposed developer
2 quoting a price, what we like to do is simply
3 recommend that you use the impartial objective
4 reports that we referenced, or any other one that
5 you can come up with.
6 But, we think that the number that you
7 generated independently are high. Hybridized
8 solar plant combined with combined cycle plant
9 does offer flexibility and allows utilities to use
10 the least cost best fit criteria to maximize use
11 of this technology.
12 It definitely provides a lower than
13 stand-alone pricing, and we're looking at probably
14 anywhere from 10 to 20 percent cost reductions
15 from the stand-alone price.
16 There's other hybridizations possible
17 with biogas and geothermal.
18 Conclusion and recommendation. Again,
19 we feel the solar energy costs in the draft report
20 needs to be revised to reflect STAT or state of
21 the art, up to the date solar design and cost. In
22 addition, we'd like to have another line, if you
23 will, in the report or description that shows a
24 solar thermal that uses a hybridization concept
25 with a combined cycle.

1 And again, maybe a mention that we
2 haven't done significant work in this area, but
3 you definitely can hybridize with geothermal and
4 biomass. In particular, geothermal is attractive,
5 because basically if you use what you call a flash
6 system, what they generate is saturated steam.
7 And we can take that saturated steam and add pure
8 super heat to it. So every solar Btu that you put
9 into the cycle basically comes back to you at the
10 efficiency of the turbine of the generator.
11 So right now when you go through a
12 traditional -- cycle, we're about 37 percent
13 efficient. But if you add it to a geothermal
14 cycle, you're about 90 percent efficient, because
15 you're just adding super heat. And the only loss
16 that you incur is with the turbine and the
17 generator. The turbine's about 90 percent
18 efficient; generator's about 98 percent efficient.
19 So you don't have to go through that latent heat
20 vaporization concept, because it's already being
21 performed for you with the geothermal cycle.
22 That's it. Any questions?
23 CHAIRMAN KEESE: What is your timing on
24 these projects?
25 MR. SKOWRONSKI: 2007, 2008, depending

on the permitting process. If we go with the George Air Force Base, that probably will be quicker. Harper it's more of a start-again of the permitting process.

CHAIRMAN KEESE: Thank you.

MR. BADR: I really appreciate your input on this, but before you leave, your numbers are site specific. Basically you looked at High Desert and you analyzed the High Desert and how you can tag along on High Desert, and you put your solar system. And you used the waste steam basically from the steam turbine or the waste heat. And you used it for your molten source, or for your reservoir to continue with the --

MR. SKOWRONSKI: We're not looking at storage, per se.

MR. BADR: Okay.

MR. SKOWRONSKI: Storage, we're not looking at storage, per se, with a combined cycle. We would just ride on the combined cycle. In other words, we provide duct firing. And if we ran into clouds or maintenance, you still get the capacity through the duct firing.

MR. BADR: Okay. The second question is can you provide some numbers to this technology?

1 You mentioned something about 7 cents and 10
2 cents, that's what I heard, 8, 10 cents, or
3 something like that. Can you provide some, you
4 know, assumptions. Assumptions like I spelled out
5 in my appendices. For this particular technology
6 and how you derive that number?
7 MR. SKOWRONSKI: No. I'm not being
8 facetious. Actually, we had a long conversation
9 with my boss, and we just think that the playing
10 field is highly competitive, and we reserve, you
11 know, the right to be relatively secret.
12 Besides, manufacturers' estimates
13 sometimes are, you know, self serving. What we'd
14 like to do, again, is just reflect back to the
15 objective reports that have been done, that we've
16 had input into these reports.
17 But to get into the specificity of
18 pricing, we think we'd undermine ourselves.
19 MR. BADR: There is a lot of
20 assumptions. As you see, there's 13 different
21 tables in every appendix for every technology. To
22 chase a new technology such as yours, and you tell
23 me that you are not willing to provide any
24 information about it because it's so secretive,
25 where do you think I should be going out and grab

1 these numbers, or find these numbers?
2 And how close are these numbers to what
3 we have? It seems like you took the combined
4 cycle out of the equation of generating what you
5 are doing because you are tagging on the combined
6 cycle. This is very similar to appendix N, when
7 we used the thermal plus gas, but minus the gas
8 because you already have an existing gas power
9 plant.
10 Our number shows 15 cents. You are
11 talking about 10 cents. If you take the capital
12 costs associated with the gas part of that
13 component, perhaps it would come pretty close to
14 where you are talking about, -- this is true.
15 MR. SKOWRONSKI: In general we think the
16 reports are pretty close to our estimates. The
17 two reports that both the CEC participated in, or
18 one of them anyway, we participated input on both
19 these reports.
20 And we'll work with you as much as I can
21 with respect to, you know, the cycle that we're
22 trying to define. But it's not just added gas
23 costs, because when you combine cycle the concept
24 you're adding heat at the right places and there
25 is a synergistic relationship on the efficiency of

the solar Btus.

MR. BADR: I wasn't mentioning just the gas; the components also -- the gas, as well, like the --

MR. SKOWRONSKI: Okay. We'll get something to you, but again, excuse my cryptic behavior, but you know, we're knocking on doors and we're talking prices, and you know, that's the name of the game we have to play.

MR. BADR: Right. Thank you.

MR. ALVARADO: I think I can say that this is the end of this workshop.

CHAIRMAN KEESE: That's it?

MR. ALVARADO: I don't know if there's anyone else of the last few folks over here?

MR. SKOWRONSKI: I got a question.

MR. ALVARADO: Sure, Mark, please.

MR. SKOWRONSKI: On your schedules, the listings of technologies and pricing, I notice you have fuel cells and fuel cell hybrid in particular that it seemed extremely optimistic, especially on the hybrid. You showed 2004 a cost around 10 cents. And I happen to own the patent -- I don't own the patent, Edison owns the patent, but I'm the inventor of the small turbine fuel cell

1 hybrid. And I stayed pretty close with that
2 technology.
3 And I called GE and Westinghouse and
4 they're talking about 2007, 2008 before that
5 technology will be available. And even then
6 they're talking about niche markets. So
7 commercial viability probably is at least six,
8 seven years away.
9 MR. BADR: So you think the numbers are
10 high or low or --
11 MR. SKOWRONSKI: Well, I mean nothing's
12 going to come online in 2004. You'll probably
13 wait another five years before you have the market
14 entry in that technology.
15 And probably at that time I would think
16 the numbers do look about right. But, it's not
17 going to be next year.
18 MR. BADR: So what you are telling me is
19 that we should scrub it, take it out of the report
20 or --
21 MR. SKOWRONSKI: Yeah, I don't think
22 it's viable. It's not there yet. GE just staffed
23 up in Torrance to produce the product. And
24 Siemens-Westinghouse has hit a snag because it
25 didn't really work. They tested it down at UCI

and they had some turbine problems. And they're putting it back another year, year and a half.

MR. BADR: But I also heard you saying that if it comes online in year 2008, 2007, or 2009, you think the numbers would be correct?

MR. SKOWRONSKI: My gut feel it's about right, yes.

MR. BADR: So I think you have no objection, there is no harm to having it in the report then?

MR. SKOWRONSKI: Well, 2004, I mean you're saying that might be a viable option for somebody in the near term, and I don't agree with that.

MR. BADR: Thank you.

MR. HALL: Hi, Stephen Hall. I'll try to keep this very very quick because I know everyone wants to go home.

I just had a question/comment about the capital costs for the natural gas combined cycle plant. And specifically around the issue, the old bugaboo about externalities.

There is a capital cost in there of $25 million for pollution control equipment. But beyond that, of course, there is greenhouse gas

1 emissions, emissions of NOx, precursors of ozone,
2 et cetera.
3 And I guess my question to the
4 Commission is, is there a policy rationale for
5 excluding environmental externality analysis in
6 looking at natural gsa combined cycle?
7 CHAIRMAN KEESE: Well, I would defer to
8 staff, but I don't think we looked at
9 environmental externalities. I think --
10 MR. BADR: Well, -- go ahead, sir.
11 CHAIRMAN KEESE: Go ahead.
12 MR. BADR: Well, you talked about two
13 things. NOx, for example, and all the criteria
14 pollutant are required by law to be mitigated.
15 MR. HALL: Right.
16 MR. BADR: So, one might argue that
17 since they are fully mitigated and that cost is
18 being paid for, this is not external costs anymore
19 because it's already built in. Okay? So the cost
20 of the criteria pollutant, let me spell them for
21 you, NOx, SOx, PM10, CO -- CO sometimes is not
22 mitigated -- and PM10. Those would be required by
23 most of Air Quality Management Districts to be
24 mitigated.
25 So, however there is a CO2 emissions,

that's not required to be mitigated. And there is other environmental costs, not necessarily emissions, but could be like as I mentioned earlier in my caveats, biology, land use, visual, you name it, water quality. There's other aspects of that. It's not included, and the reason it's not included here, not because of any policy the Commission has, because it's a site specific --

CHAIRMAN KEESE: Site specific, that's what I would think.

MR. HALL: Um-hum.

MR. BADR: Right. It's not -- if I do externality, I would have tons of argument about the numbers, and I deviated away from the cost or the comparison costs of what we tried to do. The focus of the work is to be able to compare between this technology and the same level plane.

So if I have to add externalities, perhaps I would just direct everybody to look at that, not necessarily what we're trying to do. This is one thing.

The other thing is using this report, the way you should be using this report is to be able to compare the analysis or compare the technologies to each other; not use that

1 particular absolute value for that particular
2 technology, as a cost to develop it. To be able
3 to compare, just a rate to say, okay, which one is
4 which, and what kind of technology do I need to
5 have in my portfolio and which one I don't want to
6 have in my portfolio.
7 So, not necessarily because we didn't
8 add a lot of things like externalities is one of
9 the thing. So, you know, you have to acknowledge
10 that. You don't just use that number by itself to
11 just comparison, as a comparison to put like
12 ranking between all these technologies.
13 MR. HALL: It's site specific is what
14 you're saying?
15 MR. BADR: It is site specific. All the
16 mitigations are site specific. We can give you an
17 example, a quick one because we are really late.
18 MR. HALL: Yeah.
19 MR. BADR: If you will buy -- if you are
20 siting a power plant in the Bay Area Air Quality
21 Management District, and you wanted to buy PM10,
22 good luck. All right? Because they don't have
23 any, or they are running very dry.
24 Okay, now if you go to San Joaquin
25 Valley you perhaps have a better luck. The cost

of the PM10, a ton of PM10 in the Air Quality Management District could be humongous. I don't want to give a value on it.

If you go down to San Joaquin Valley perhaps you get $3000, $4000, which is very reasonable.

So you have other things also. The permit application, itself, is $350,000 for AQMD in the Bay Area. You go somewhere else, maybe $20,000, maybe none. So it depends. These values vary a lot, you know, it's not like a small difference. It's a huge differences between them, and depends on what is required to be mitigated and what's not required to be mitigated.

I'll be very reluctant to consider this externalities or societal cost to add here. The reason, again, for that report is to establish costs for to develop that technology, and be able to compare between these technologies together.

MR. HALL: Um-hum.

MR. BADR: Okay? And I think I give a lot of credit to my colleague, Benjamin, for choosing the title correctly. It's a comparative cost of technology for the electricity generation technology. Okay?

1 So it's not meant to be an absolute
2 value. You will say, okay, I want to sign a
3 contract for that because CEC told me that. All
4 right? That's why the reason for the caveats.
5 MR. HALL: Okay. But maybe for
6 greenhouse gas emissions, which are not site
7 specific, that environmental adder could be
8 considered?
9 Anyway, thanks very much.
10 MR. BADR: I'm sure.
11 CHAIRMAN KEESE: Yes. I'm sure, you
12 know, once we get around to policy, this is not
13 policy yet. I mean it has policy implications.
14 But once we establish the baselines in all this,
15 then we move on to policy. And what is the
16 policy. And I'm you know, sure renewables are --
17 the renewables are going to be a part of the
18 picture. Not picking the lowest cost generating
19 system in the state.
20 Well, I thank all the diehards for
21 hanging in here.
22 MR. SKOWRONSKI: All four of us?
23 CHAIRMAN KEESE: Yes.
24 MR. BADR: Thank you, Commissioner, for
25 sticking.

1 CHAIRMAN KEESE: Thank you. It's a two-
2 day good start. Thank you, Karen. Sort of messed
3 up your schedule, too.
4 Thank you, everybody.
5 (Whereupon, at 5:50 p.m., the workshop
6 was adjourned.)
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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 2nd day of April, 2003.