DOCKETED	
Docket Number:	19-IEPR-09
Project Title:	Southern California Energy Reliability
TN #:	228898
Document Title:	Transcript of 05-23-2019 Workshop
Description:	N/A
Filer:	Cody Goldthrite
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	7/3/2019 8:15:07 AM
Docketed Date:	7/3/2019

CALIFORNIA ENERGY COMMISSION

JOINT AGENCY WORKSHOP

In the Matter of:	)	Docket No. 19-IEPR-09
	)	
	)	
2019 Integrated Energy Policy Report	)	Southern California Energy Reliability
	)	

CALIFORNIA ENERGY COMMISSION (CEC)

CALIFORNIA ENERGY COMMISSION

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT, AUDITORIUM

21865 COPLEY DRIVE

DIAMOND BAR, CALIFORNIA 91765

THURSDAY, MAY 23, 2019

10:00 A.M.

Reported by: Troy A. Ray

APPEARANCES

COMMISSIONERS AND EXECUTIVES PRESENT:

Chair David Hochschild, California Energy Commission
Vice Chair Janea S. Scott, California Energy Commission
Commissioner J. Andrew McAllister, California Energy Commission (via WebEx)
Commissioner Liane M. Randolph, California Public Utilities Commission
Commissioner Clifford Rechtschaffen, California Public Utilities Commission
Commissioner Martha Guzman Aceves, California Public Utilities Commission
Mark Rothleder, California Independent System Operator
Reiko Kerr, Los Angeles Department of Water and Power
Laki Tisopulos, South Coast Air Quality Management District

CEC STAFF PRESENT:

Heather Raitt, California Energy Commission
Lana Wong, California Energy Commission

PANEL

Neil Millar, California Independent System Operator
Simon Baker, California Public Utilities Commission
Rabindra Kiran, Southern California Edison
David Thai, San Diego Gas & Electric
Jason Rondou, Los Angeles Department of Water and Power
Brad Bouillon, California Independent System Operator
Glenn Barry, Los Angeles Department of Water and Power
Matthewson Epuna, California Public Utilities Commission
Rod Walker, Walker & Associates
David Bisi, Southern California Gas Company
Jennifer Walker, Southern California Gas Company
Dan Rendler, Southern California Gas Company
Jimmie Cho, Southern California Gas Company
Neil Navin, Southern California Gas Company

PUBLIC COMMENT

Issam Najm, Porter Ranch Neighborhood Council
Sarah Reese, South Coast Air Quality Management District

INDEX

		Page
1.	Call to Order	4
2.	Joint Agency Update on Reliability Issues Including Phase Out of Once-Through Cooling (Lana Wong, Neil Millar, Simon Baker)	10
3.	Utility Update on Reliability Issues Associated with Phase Out of Once-Through Cooling (Rabindra Kiran, Gene Lee, David Thai, Jason Rondou)	36
4.	Update on Reliability and Other Issues Associated with SoCal Gas Infrastructure Challenges (Simon Baker, Lana Wong, Brad Bouillon, Glen Barry)	79
5.	Other Safety and System Operations Perspectives (Matthewson Epuna, Rod Walker)	114
6.	Update from Southern California Gas Company on Summer 2019 Technical Assessment, Demand Response, and New Gas Hookups (David Bisi, Jennifer Walker, Dan Rendler, Jimmie Cho, Neil Navin)	144
7.	Public Comment	181
8.	Adjournment	187
Reporter's Certificate		188
Transcriber's Certificate		189

P R O C E E D I N G S

MAY 23, 2019 10:00 A.M.

VICE CHAIR SCOTT: All right. Well, good morning everyone and welcome. We're going to start with some logistics and updates by Heather Raitt.

MS. RAITT: Good morning. I'm Heather Raitt, the Assistant Executive Director of Policy Development and the Program Manager for the IEPR, the Integrated Energy Policy Report. And so this proceeding today is part of that -- this workshop is part of that proceeding.

So I'll go over the housekeeping items. So restrooms are located down the hallway across the auditorium entrance. We'd like to request no food in the auditorium please but capped water is fine. And just a reminder to please place your cell phones on silent or vibrate. If there is an emergency and an evacuation is called, please exit the building through the doors at the back of the auditorium. And if there is a shelter in place if necessary, please drop and cover your head and hold your chairs such as for an earthquake.

Today's workshop is being broadcast through our WebEx conferencing system so everyone should be aware that it is being recorded. We'll have an audio recording posted on the Energy Commission's website and we will also have a written transcript and all of that will probably take a few weeks.

We do have a very few -- a very full agenda so I'd like to remind our speakers to please stay within your allotted times.

At the end of the workshop we will have an opportunity for public comments. For those in the room that would like to make comments, please fill out a blue card and you can get it to our public advisor. And we'll take the comments, like I said, at the end of the day.

We'll also have an opportunity for WebEx participants to comment, and you can use the raise your hand feature to let our WebEx coordinator know that you would like to comment.

Copies of the presentations and reports are all available on the Energy Commission's website. And written comments are welcome and can be provided after the workshop. And the notice provides all the information for how to do that and they're due on June 6th.

So with that, I'll turn it back to the Commissioners and Executives. Thank you.

VICE CHAIR SCOTT: Great. Thank you so much, Heather.

Well, good morning and welcome everyone. I'm Vice Chair Janea Scott, of the California Energy Commission. And I'm also the lead this year on our 2019 Integrated Energy Policy Report, or the IEPR. Today's joint agency workshop will be included in this year's IEPR.

So I'd like to start off with a few comments and then give my colleagues a chance to introduce themselves.

Today's workshop will be the fifth workshop the joint agencies have conducted since April of 2016, to address energy reliability risks facing the Southern California region. This assessment looks at the short-term issues facing the region over the coming summer months. And in recent years, expected and unexpected events have greatly impacted and threatened Southern California's electric reliability. These events include the well leak at Aliso Canyon, the early retirement of the San Onofre Power -- Nuclear Power Station, the planned retirement of once-through cooling power plants along our Coastline, and most recently the longer than expected pipeline outages on SoCal Gas's system.

We have a full agenda today with presentations and discussions about the risk assessment for this summer, which I will add those risks are lower today than they were in 2016 primarily due to electric transmission upgrades. However, our greatest risk now stems from pipeline outages that continue on Southern California's Gas's System. We're going to hear about the status of those outages, why they are still ongoing, and the concern that there may be more.

A few utilities will provide updates on how they are managing their resources and agency staff will discuss possible measures that may mitigate the risk of broader service outages while these pipelines are down. We will also hear from an independent expert who will share insight from outside California as well as other stakeholder representatives.

I look forward to good discussions throughout the day and want to thank everyone for their participation. I especially want to say thank you to our colleagues from the CPUC, the California Independent System Operator, Los Angeles Department of Water and Power, and the South Coast Air Quality Management District for being here and for South Coast for hosting us today.

So now we'll hear some opening remarks from Commissioner Liane Randolph and then we'll turn to the introductions of the other folks on the dais.

Commissioner Randolph.

COMMISSIONER RANDOLPH: Thank you to Vice Chair Scott for convening this group and inviting us here, and I look forward to the discussion today. And thank you to our host AQMD for hosting us here, we appreciate it.

As Commissioner Scott mentioned, the pipeline outages continue to be a critical concern that is affecting electric reliability and the continued restrictions on Aliso Canyon also coupled with those pipeline outages create challenges that even FERC's office of Electric Reliability and Enforcement have highlighted as concerns on the Western Interconnection. So I think this is a really important discussion to have.

We at the PUC continue to closely monitor the outages and how the company is handling the outages. I asked my chief of staff recently to go out into the field and visit the repair sites at Line 235. And so she had an opportunity to go out and see the conditions out there, and we are engaging on a weekly basis with the Safety and Enforcement Division as they are monitoring those repairs, and the status of those repairs, and what other potential repairs may need to occur that could limit the ability to bring 235 back into service.

As I'm sure many are also aware, the CPUC and DOGGR announced the independent root cause analysis prepared by Blade Energy Partners was released. That is not going to be a topic of discussion at today's meeting, there will be a future meeting set up to have more of a complete discussion about the root cause analysis. But I did want to make sure that folks were aware that that analysis is available on our website if you want to take a look at it and review it.

So I appreciate everyone participating today and I look forward to the robust discussion. Thank you.

VICE CHAIR SCOTT: Great. Thank you very much.

Let's do introduction of the folks on the dais and maybe I'll start over here to my right, with Mark.

MR. ROTHLEDER: Thank you. I'm Mark Rothleder, vice president of Market Quality and California Regulatory Affairs of the California ISO. Thank you.

MS. KERR: Good morning. I'm Reiko Kerr, the senior assistant general manager for the Power System at Los Angeles Department of Water and Power.

CHAIR HOCHSCHILD: Good morning. David Hochschild, Chair of the California Energy Commission.

MS. ACEVES: Morning. Martha Guzman Aceves one of the commissioners at the California Public Utilities Commission.

MR. TISOPULOS: Good morning. Laki Tisopulos, deputy executive officer with South Coast Air Quality Management District. I want to take this opportunity to welcome you all and thank you for holding this workshop on this very important topic here in the Southland and wish all of us, the audience, a very productive workshop.

VICE CHAIR SCOTT: Thank you for hosting us. Let me turn to Commissioner McAllister.

COMMISSIONER MCALLISTER: Oh hey, this is Andrew McAllister, Commissioner at the California Energy Commission. I'm remote from Sacramento. Good to be with you all.

VICE CHAIR SCOTT: Glad to have you.

I will just make note for the public that Heather said this just a few minutes ago, but if you would like to make a comment, please fill out a blue card, you can find those on the table that were there in the entrance on your way in. If you'll hand those kindly to our public advisor or to Heather and they'll get those to us and that's how we'll know that you'd like to make a public comment.

With that, let us turn to our first panel of the morning. And we will begin with Lana Wong.

MS. WONG: Good morning. I'm Lana Wong, senior staff with the Energy Commission.

This first panel is going to touch on a number of issues associated with reliability in Southern California as a consequence of the unexpected retirement of the San Onofre Nuclear Generating Station, also known as SONGS, that occurred back in 2013. And also our planned retirements of once-through cooling plants. A plan was put in place to deal with the unexpected retirement and the phase out of the OTC and we're here to report on the progress.

I'll start with a brief overview of once-through cooling that really is a success story of how the OTC policy is achieving our environmental goals. Once-through cooling is a process whereby coastal power plants intake ocean water and they use that to cool the turbines. And it's a process that's been going on for a long time as some of these plants are very old, were built in the '50s.

But once-through cooling or OTC does cause significant harm to marine life. As a result, in 2010 the State Water Resource Control Board adopted a policy to phase out once-through cooling at all the coastal plants in California. And in doing so, they created an advisory body called the Statewide Advisory Committee on Cooling Water Intake Structures, also known as SACCWIS.

So if you look up on the screen, you'll see all of the agencies that make up SACCWIS and provide advice to the State Water Board. SACCWIS's task with ensuring grid reliability during the phase out of OTC. And so several of the plants are located in the Southern California area.

SACCWIS does a report every year about this time to the State Water Board and I'm going to give you an overview of the presentation made to them this past Tuesday. So I'm a member of the interagency working group, it's a technical team that supports staff and that prepares the report for SACCWIS.

So this is essentially the highlight of the SACCWIS report. No recommendations for changes to OTC compliance dates. However, we tee up the potential need for the compliance date extension due to a transmission upgrade delay that's currently being studied by the ISO. You'll probably hear a little bit more about that later today. But at this time, no date change is recommended.

So this slide gives you an overview of the current status, and the policy impacted 19 power plants along the coast and that's about 20,500 megawatts and about half the megawatts are in compliance. So ten plants fully in compliance and four that are in partial compliance.

We've got another 6300 megawatts that are expected to comply by the end of 2020, next year, and about 3800 megawatts of that's located in the L.A. Basin. And so after 2020, that'll essentially bring the total compliance to 80 percent by 2020. And the remaining OTC have compliance dates out through 2029.

So this is a map of the locations of the OTC plants and you can see that they're located up and down the state but the inset diagram shows the ones that are in the L.A. Basin and San Diego area. And those regions were the area that were impacted by the unexpected retirement of SONGS.

So this slide shows all of the plants that have achieved compliance so that's about half the megawatts as I mentioned earlier. If you look at the last row, the Encina Power Plant, so the Encina Power Plant was given a one-year extension of its OTC compliance date to allow the Carlsbad facility to come online. That plant came online at the end of last year and that allowed Encina to retire in December of last year.

This slide shows the remaining megawatts that still are in the process of achieving compliance. You'll notice a number of them have a 2020 compliance date, to draw your attention to the ones in the L.A. Basin region; that's Alamitos, Huntington Beach, and Redondo Beach, they all have 2020 compliance dates. And if you notice, there's a few units at each of them, Alamitos 1, 2, 6, Huntington Beach 1, and Redondo Beach 7 that all plan to retire early this year to provide emission offsets for the new Alamitos and Huntington Beach repowering projects that are currently under construction.

So this slide shows the water usage at the facilities and shows the progress that we've made to date on achieving our environmental goals. So the upper blue line is based on the design flow of the OTC fleet and the Water Board's Compliance Schedule. And the green line below it shows design flow and basically early retirements or accelerated retirements. And then the red line is the actual water flow through the power plants based on EPA data. And you can see that the red line is much lower primarily due to the fact that many of these plants run at a much lower capacity factor than its original design.

So I had mentioned that a plan was put in place. It was a multipronged plan comprised of preferred resources, transmission solutions, and conventional generation. And later in the panel you'll hear about preferred resources and transmission solutions, and I'm briefly going to touch on the conventional generation.

So the first plant, Alamitos. This plant is under construction and it is 85 percent complete and on track to be online in spring 2020. It is a 640-megawatt repowering project. And so one note about this project is that the transmission upgrade that's been delayed that I mentioned is currently being studied, depending on the outcome of that study, it may require an extension of an OTC facility and Alamitos is one that is being reviewed to determine whether a OTC compliance date extension would be needed.

Huntington Beach. This is also a repowering project, it's about 644 megawatts. This one is also under construction and about 88 percent complete. It's also on tract to be online in the spring of 2020.

Redondo Beach. The key takeaway on this slide is that AES has sold two parcels at the Redondo Beach site, the remaining property is in escrow and is expected to close in 2019. Currently there is an application for certification that's been suspended at the Energy Commission but if the sale of the property closes, that will be terminated at the Energy Commission.

This last project, Stanton Energy Reliability Center, this is not an OTC plant but I included it because it was one of the projects selected out of Edison's 2013 Request For Offer. It has a contract and its application for certification was approved by the Energy Commission last November, and it is currently under construction and about 5 percent complete. It's scheduled to be online next year.

The transmission project that I mentioned has been delayed, is the Mesa Loop-In Project. The study is underway and is expected in June, Neil will probably talk more about it so I'll leave that one for him.

So in conclusion, no recommendations are made at this time to compliance dates. ISO, Energy Commission, PUC will continue to monitor the situation to ensure reliability. And SACCWIS will reconvene if necessary, depending on the outcome of the study underway. Thank you.

VICE CHAIR SCOTT: Well, actually, Neil, right before you get started, I want to welcome Commissioner Cliff Rechtschaffen from the PUC to the dais. Welcome, good morning.

And I believe we also have Commissioner Karen Douglas on the line as well. So good morning, Karen, and welcome.

Okay. Thanks, Neil.

MR. MILLAR: Okay. Good morning and thank you.

Yes, I'm Neil -- excuse me, Neil Millar, executive director of Infrastructure Development at the ISO. And today I'd be focusing on giving you an update on the local issues affecting the L.A. Basin and San Diego requirements, really tagging on to Lana's Presentation.

As an overview, I should just mention upfront that we're a year further down the line from last year. The good news is that there have been no unexpected surprises. So we're on track with what we predicted last year which also means the continued concern around the possible need to extend the Alamitos Plant. So setting that aside, which was also identified previously, there really are no surprises other than that we've just moved forward down another year.

As was discussed earlier, just to clarify that, yes, the plans that were in place to address the once-through cooling retirement had to be accelerated and expanded to accommodate the unexpected retirement of San Onofre. Without those changes we were looking at potential voltage collapse in the area as well as thermal transmission line overloading. So there was a delicate balance of needing to address both of those issues.

Overall, when we look back at the progress that was achieved, we do consider this a very positive story. Less than half of the overall gas fired generation and the ISO portion in the L.A. Basin, San Diego area is being replaced and that's despite the unexpected loss of San Onofre. So that was accommodated through, as Lana mentioned, a combination of various solutions including preferred resources, some conventional replacement, and a number of transmission upgrades.

Now, the -- from the perspective of the different types of projects, resource procurement including preferred resources both in the L.A. Basin and San Diego played a major role. We also relied very heavily on dynamic reactive support devices, synchronous condenser projects going through in a number of areas, and that was also where we turned to Huntington Beach to provide some interim service with Units 3 and 4 operating as synchronous condensers. We were very happy to be able to allow those units to retire as the new generator -- as the synchronous condensers came online.

The other key transmission projects -- there were a number of smaller upgrades, but a number of key transmission projects that were instrumental in allowing us to move forward including the Imperial Valley Phase Shifting Transformer that helped manage flows into the San Diego area. Sycamore-Penasquitos Transmission line, the Mesa Loop-In Project will also play a major role, and we have other upgrades that we’re looking at that weren’t targeting 2021 but will provide additional relief in the future.

Now, the primary concern at this point does remain the low-voltage concern feeding into the northern end of the L.A. Basin where we are requiring the additional support from the Mesa Loop-In Project which is really the tapping of the

Mesa Mira Loma line into a new -- to create a new source into the 230 kV system. And I believe the representative from Southern California Edison will be talking more about that.

Overall, the mitigations have been largely moving forward as planned and where there were delays, we were able to accommodate those. The Carlsbad Energy Center in service had been delayed, and the Encina OTC extension helped us match that. The Sycamore-Penasquitos project had taken a bit longer than originally planned when the decision was made to move underground, and we were able to find operating solutions to mitigate until that project came in place.

The Mesa Loop-In Project remains the active concern. The project, Southern California Edison have been working to advance the in service date from its current expectation or current target of March 2022. Even if they're successful, we don't expect realistically that there's a chance of getting the project in before the summer of 2021. We would obviously prefer to see the project in as early as possible, but we do see needing to be planning for the summer of 2021 assuming that the Mesa Loop-In is not in service.

Now, what that means is fine tuning our studies to determine if we need to defer Alamitos and to what extent -- or defer its retirement to the remaining units and to what extent.

One of the things that we've had to take into account in this analysis is that the peak demand forecast in these areas is relatively volatile subject to change based on environmental conditions and year over year learning. So there has been slight downward pressure on the forecast for the area. So that is why we are looking at conducting and we're in the middle of conducting a special study focusing on the L.A. Basin requirements for the summer of 2021 which would be the basis for starting the process, if necessary, for an extension to the OTC compliance date with the State Water Board.

So normally our studies at this time would focus on 2020, but the 2021 work is a special effort just focusing on this particular need. We wouldn't be expecting that to determine the final megawatt number that we actually require because there would be another study being conducted next year as well. But we do need to take into account the OTC compliance date requirements with the Water Board and the reasonable timeline it takes for them to identify and grant an extension.

One of the other issues that we identified last year that we also have to take into account is that while the peak demands in these areas have been relatively constant, the time of day has been shifting to later in the day when the peak is experienced. And one consequence of that is that it puts more pressure on the ability for grid-connected solar resources to play a part in meeting the local needs.

So we do have to take into account that as the peak moves later in the day, we are less able to count on grid-connected solar as part of the -- meeting the need of the local peak -- peak demand.

This graph is also just a broader picture showing for the San Diego service territory overall. Just demonstrating how the behind the meter rooftop solar that's been connected has had -- had an initial result of putting downward pressure on the forecast but now additional rooftop solar is simply moving the peak out to a bit later in the day.

So our next steps going forward are really focused. We don't consider it credible that the Mesa Loop-In Project could be advanced to before the summer of 2021 but we are continuing to work with Edison on that. And in the meantime, studying the local capacity requirement to determine if it is necessary to seek an OTC extension for Alamitos and to try to give an estimate of the capacity requirement that that would take.

Now, the other -- what I haven't touched on in this presentation are the gas supply concerns. I've been focusing on the transmission infrastructure and generation infrastructure overall. Of course, the concerns around the natural gas system will be addressed separately.

I'll stop there and see if there are any questions I can help with.

VICE CHAIR SCOTT: Why don't we -- we'll do all three presentations and then we'll take questions from the dais, unless there's a burning question right now.

MR. MILLAR: Thank you.

VICE CHAIR SCOTT: Okay. Thank you. Simon.

MR. BAKER: Good morning, Commissioners.

So the Public Utilities Commission's role in this is with regard to overseeing and directing the procurement of the investor-owned utilities and also administering the Resource Adequacy program for all load serving entities.

So we've been asked to speak a little bit about what the PUC has done to oversee the procurement of replacement capacity for the once-through cooling plants that are retiring. As was noted earlier, about 9500 megawatts of CAISO area capacity is due to retire in California by December 2020. And so the PUC has in our proceedings overseen 3000 megawatts or procurement that's been approved or is under review, contracts that have been signed and are under review. That procurement authorization came out of our long-term procurement plan proceeding in two tracks, the Track 1 and Track 4 decisions. And the way that breaks down is we have about 2200 megawatts of new or existing gas power plants that have been procured. And the good news is we have about 800 megawatts of preferred resources that have been procured out of that process.

So given that we've heard about the situation in Southern California and the picture looks relatively good, at least for the summer of 2019, we thought it would be beneficial to zoom out a little bit and look a little bit more broadly at system level, Resource Adequacy issues that we're seeing in our program. So this slide shows for 2019 the total Resource Adequacy mix, relative to the Resource Adequacy requirements that we're seeing.

And the Resource Adequacy requirements are shown in the lines that cut across this graph. The one of -- that we want to highlight here today is the red line which is the system Resource Adequacy requirements which includes the reserve margin. And as you can see, the resource stack that we have here for 2019 primarily gas in pink, and then stacking up to solar in yellow, and wind in blue, and then we have imports there at the top. And the main takeaway of this is just to show that there's a general tightening of Resource Adequacy supply, and this is because the system is starting to kind of approach what we would call right sizing.

And also it shows that we're increasing relying on imports in peak months. So you can see that in July, August, and September, we're increasingly relying on imports to meet our system Resource Adequacy requirements.

At the same time, we're also seeing a change in the way that retail electric load is being served in California by an increasing number of load serving entities. So in 2014, there were 18 load serving entities serving load the three investors in utilities, 14 energy service providers, and one community choice aggregator.

Today as of May 2019, there are 36 active load serving entities and the primary growth is due to CCA growth, there are now 19 CCAs that are regulated to serve load. And the Commission has received another nine implementation plans and three expansion plans for 2020.

We're also seeing an imminent growth in direct access load due to the partial increase in the direct access cap from SB 237. And so the charts at the bottom, they basically show the trend over time from 2014 with the growing wedge of community choice aggregator load in red going from 2018 share of load of 13 percent to 2019 share of load of 25 percent. And then in 2020 and beyond, we're going to start to see some changes there in that green wedge of ESB load due to the increase in direct access cap.

So when you put these two pieces together, what you're seeing is you're seeing a tightening in the overall supply of Resource Adequacy in the state which is, as was said earlier, increasing our reliance on out-of-state resources during peak months. And this is a -- this is a concern because well -- because of climate change, our reliance on out-of-state hydro becomes increasingly uncertain. And also because of retirements throughout the western interconnect of coal and other generating resources, our ability to retire -- to rely on those out-of-state resources becomes more uncertain as other areas may need those resources.

We've also seen unexpected mothballing of plants and retirements of plants which is reducing in state capacity further. So in -- and also in addition to that in the Resource Adequacy proceeding the -- there's a proposal of staff to revise the calculations of the net qualifying capacity of solar and wind resources which would result in an overall reduction of the contribution towards capacity from those resources by about 15 percent -- 50 percent.

So these things in combination are contributing to the -- this tightening of system supply. In addition, because of the changes in the retail market landscape, we're seeing some potential market power concerns, especially within the transmission constrained areas and subareas due to this right sizing of supply that I was -- spoke about earlier.

CHAIR HOCHSCHILD: Sorry, could you -- could you go back to the -- what is driving a 50 percent reduction in the ELCC? Can you explain that --

MR. BAKER: What it is is that we are modifying the methodology within the resource adequacy proceeding. There's a proposal to modify the methodology to account for changes that we're seeing in the contribution of these resources towards peak capacity.

COMMISSIONER RANDOLPH: Is that due to the peak shift that you were talking about earlier just in terms of more behind the meter or do you have any more detail on what's driving that?

MR. BAKER: That's one contributing factor, Neil might be able to chime in here as well, and we're also looking at some of the more technical aspects of the methodology and how probabilistic assessments, when you refine those methodologies result in more conservative estimates about the contribution towards peak.

Okay. So just to continue on with the -- so we're seeing some, as was noted earlier, the retail market fragmentation. And what this is doing is they're -- because of the way that power is procured, it's often procured in a lumpy way. So as you get a -- multiple different buyers for the Resource Adequacy capacity, we're seeing some irregularities in the market, and as a result we've seen 11 requests for Resource Adequacy waivers both in 2018 and in 2019.

So what are we doing about this? What are some possible solutions? One option is to consider requiring additional procurement of new or mothballed resources and this is an issue that the Commission plans to take up in the integrated resource planning proceeding which is the successor to the long-term procurement plan proceeding where a new track has been opened to consider short-term procurement needs that may exist.

Also in the Resource Adequacy proceeding there's a newly adopted requirement for multi Resource Adequacy procurement and this is designed to discourage the exit of existing resources. So a decision in February of this year approved a three-year requirement for local capacity requirements. And in addition, the parties in the proceeding are considering a mechanism for a centralized procurement mechanism for local capacity.

The Commission also took action in 2018 to procure certain OTC capacity up to compliance deadlines, went -- took an action to require the Southern California Edison to procure capacity for Ormond Beach and Ellwood through December of 2020.

And then we're aware as well that the CAISO is now considering potential modifications to mothball and retirement rules in their Resource Adequacy enhancement's initiative and we're monitoring that closely and collaborating with the CAISO on that. Thank you.

VICE CHAIR SCOTT: Great. Thank you very much.

Let me turn to my fellow dais members and see if there are questions.

Yes, Mark, please go ahead.

MR. ROTHLEDER: Yeah, Simon, I really appreciate this presentation and also the attention to the -- the system capacity situation. I think we're seeing similar tightening of conditions and I think we do share the concern and support that there needs to be some kind of action plan looking forward.

Some of the more subtleties that we're seeing is you've already mentioned, kind of that shift peak to hour ending 17 to 18 or later, and then not aligning necessarily with the solar production which reduces the contribution to the peak and that's one.

I think another thing that we're seeing, too, is the credit that -- or expectation, net qualifying capacity on the hydro sometimes will -- may exceed what we see as maximum hydro production in reality. So that may be something to look at as you kind of refine the assessment.

And then the third part is the uncertainty about those imports. I think imports we are seeing, too, where at peak conditions, high-load conditions in California tends to be the period of time where the availability of that energy from outside the area tends to taper off especially in drier years.

So I think those three things in combination looking forward with kind of the roll off of that last tranche of OTC resources kind of raises some questions looking from 2019 looking forward. And I'm just curious looking back on your graph on the previous slide, on 2019 view, do you have a similar graph developed for projecting out to 2021?

I know it's hard to do that sometimes because you don't have a good view of all the resources that are going to be procured, be available at that time. But I think looking out and projecting that may be telling and maybe emphasize the importance of developing the plan earlier than later. So, that's one question.

The second question on the graph is, does the yellow, the solar, does that represent the NQC or the revised ELCC contribution at this point? Thank you.

MR. BAKER: Yeah, so we do have a graph like this for 2020 and I believe even 2021. It's just that as you noted as you start to project out further, the assumptions become more and more uncertain. And so given that today's workshop was really focusing on 2019, we thought it most appropriate to put the 2019 graph here. But we can certainly share with you what we have for 2020 and provide all the necessary caveats behind it in terms of the assumptions.

And then as far as the solar, I don't know directly the answer to your question but my hunch is that since the

ELCC proposal is only a proposal of staff at this point and it's not adopted by the commission yet, that this is probably the current NQC methodology for solar.

VICE CHAIR SCOTT: Other questions from the dais? Yes, please go ahead, Laki.

MR. TISOPULOS: The shift that you seen the peak and you were showing as on your slide the San Diego area, do you see something similar with the Los Angeles area?

MR. BAKER: I might defer that to Neil.

MR. TISOPULOS: Oh, I'm sorry, it was Neil, I think, yeah.

MR. MILLAR: Yes, it's Neil here. Yes, that was in my deck. And, yes, we see the same trend pretty much across the board. The rooftop solar has really been taking off. And that's resulted in every area where it's taking off, that shift occurring that the peak demand is gradually moving to later in the day.

MR. TISOPULOS: Got it, got it.

And Simon, one question to you. You mentioned the centralized local capacity procurement, could you elaborate what that -- what does it entail?

MR. BAKER: Yeah. It gets to some of the issues that we've been seeing in the Resource Adequacy program again because of retail market fragmentation. And so the sellers, the generators, are saying that it can be challenging to work with multiple small retail load serving entities. Many of them are very small and so they're buying very small quantities of capacity. And so especially given the strict timelines of their Resource Adequacy program of when procurement needs to happen, when showings need to be made and so forth, it can be challenging for all that to come together in a sensible way.

And so the concept in a proceeding is to consider well, might there be a centralized procurement entity that could procure on behalf of all the load serving entities and then have some cost allocation mechanisms to work out who pays for what on the backend. So that's something that's being considered in the proceeding right now.

VICE CHAIR SCOTT: Let me check to see whether Commissioner McAllister or Douglas have questions from the WebEx.

COMMISSIONER MCALLISTER: Yeah. I have a question. This is Commissioner McAllister.

You know, in our forecasting work here at the Commission and also in a couple of the presentation we heard just now, you know, there's this graphic representation of the peak shift being, you know, later and later.

And I'm just wanting to be crystal clear in my question, is the only reason for that, the suppression of demand earlier in the day and evening by solar? And the flipside of that would -- flipside question would be, is there any other dynamic going on that is pushing peak back, such as behavior or anything like that? My impression from all of our work is that -- essentially what we've got left over is a residual net demand after you sort of take out, you know, displace midday and early evening consumption with rooftop solar and solar generally.

Is that the 100 percent of the reason or are there other dynamics going on that are pushing the peak back?

MR. MILLAR: It's Neil here, I'll take the first shot at this. Our understanding is that the primary influence is the behind the meter solar. There could be smaller effects on some of the programs like energy efficiency because generally the growth -- the gross customer consumption of energy is still there, it's just being supplied by rooftop solar.

So the peak of the day is still in the highest overall consumption is occurring. So any other programs that are pulling the gross consumption down behind the meter as well could also be having an impact. That's a bit of speculation but the primary issue that we're aware of is the rooftop solar.

MR. ROTHLEDER: So since we're on the topic of load forecast itself, I believe the forecast used for the graph and the requirements is a -- what's called a one and two load forecasts. Could you -- one of you explain what one, two load forecast means and what -- well, what it means and what does it mean for potential higher or lower loads actually occurring?

MR. BAKER: Well, one and two is basically a fancy way of saying the average, it's the middle of the bell curve.

MR. ROTHLEDER: I have one more question for Neil. You mentioned the potential need for extending for the local regions for the Mesa Loop-In timing. If that were to come to fruition, what -- it seems like there's a new Alamitos resource and then potentially the existing Alamitos resource. What capacity would be available if extension were to be requested and approved?

MR. MILLAR: Yes. It's our understanding that after the units that are being retired to free up air credits and to allow the new construction to move forward and come online, that would still leave about a 1000 megawatts or just over a 1000 megawatts of capacity at Alamitos that would, all other things being considered, would be expected to retire on December 31, 2020 to comply with the OTC requirements.

Now, out of that just over 1000 megawatts, studies in the past have identified ranges of anywhere from 400 to I believe 900 megawatts of potential requirement as we've looked at different years of forecasting. So that number has moved around. There's generally been a need for some of that

1000 to be retained if the Mesa Loop-In project was delayed. So we're talking in that range but it would be out of that over 1000 megawatts that would otherwise be available at the -- or expected to retire at the end of 2020.

VICE CHAIR SCOTT: I had a question for you based on, Neil, the special study that you said you will be carrying out for the Mesa Loop-In.

Do you have a timeline for that? And then my follow-up question on that also goes to Simon about the short-term procurement process that the PUC is putting together. Are they kind of aligning such that if you identify different needs that we may need to procure for that short-term procurement process will be in place to kind of assist with that?

MR. MILLAR: Sure, yes, we do have the timeline. The timeline is that we are targeting having the study out by the end of June so that we can decide whether -- if we do have a requirement, the expectation is that we would call for a special meeting of the SACCWIS committee to make a recommendation to the Water Board for an extension.

And the timing is really driven by what it would take to give the Water Board appropriate time to get through their process to move forward with an extension. So that's why we are doing this on an accelerated basis targeting the end of June for the study and then moving in to the SACCWIS process.

MR. BAKER: And, yes that's right. Integrated Resource planning proceeding we're anticipating issuing a ruling soon to begin that process imminently.

And we also have Commissioner Randolph here, she's the lead commissioner for that proceeding as well.

VICE CHAIR SCOTT: Thank you. Yes, go ahead. Take the last question.

MS. ACEVES: Just a quick follow up to your question, Commissioner Scott.

The study that you're doing, Neil, is going to look at the entire part -- or the entire L.A. Basin or just the northern part?

MR. MILLAR: No. The study looks comprehensively at both the L.A. Basin and San Diego area requirements because the area's -- ever since San Onofre retired, we've really had to study each area individually and then the collective whole. So we're duplicating that entire analysis that's normally part of our annual one-year head study. But here we're updating it to look two years out with the latest available information. So that any recommendation we make is on -- based on the latest most up to date information possible. But it would look at the L.A. Basin, San Diego, and the combination.

MS. ACEVES: And are you also going to include -- as part of your analysis some of the alternatives as you did for

Moorpark where you looked at not just the need but preferred alternatives including additional transmission to meet the need?

MR. MILLAR: Given that this is only focusing on the summer of 2021, we've been focusing on resources that we know of that are already moving forward because that's not a lot of time to get anything new in place. So that's what we've been focusing on and we do see the solution just around the corner being the Mesa Loop-In project is coming, it's just not available for that summer.

MS. ACEVES: I see.

MR. MILLAR: So, we see it as a very short-term extension just for that specific need.

Now, any other resources that we're aware of in the meantime, we will be taking in to account in the study.

COMMISSIONER RANDOLPH: And I'll kind of add in response to Commissioners Scott's question about the sort of near-term procurement in IRP. I don't think that what we would be seeing as part of that procurement would be online for that timeframe either.

I mean, what we're still -- we'll still be working on it and that information will be useful but it's not -- I don't think they're necessarily -- that's necessarily the solution.

VICE CHAIR SCOTT: All right. Well, great first panel, thank you guys very much.

I'd like to invite our second panel to come on up.

And while we're making that quick shift, I just want to do a reminder for the blue cards. If you're a member of the public and you'd like to make a comment, the blue cards are on the table right out front. If you pick one up and you put your information on it, and then you can hand it either to our public advisor or to Heather and she'll get those to us. That's how we'll know you'd like to say something.

So give us just about 30 seconds here while our second panel comes on up. And we'll keep going. Thank you, first panel.

Okay. Like a -- almost ready. Ready? All right. Good morning.

MR. KIRAN: My name is Rabi Kiran, I'll be providing the SCE Transmission update.

So the way the presentation is broken up is it's broken up into the types of transmission projects. So we have transmission projects required for load service, transmission projects required for delivering renewables, and transmission projects required for local capacity requirements.

So this slide here talks about projects -- transmission projects required for load service. And we have two projects both located in Riverside County. The first project is the new Alberhill 500/115 kV substation, it's basically proposed to relieve overloads on the Valley 500/115 kV system by looping in the Serrano to Valley 500 kV line.

So the status of the project is that the CPCN was filed in September 2009 and amended in March of 2010. The proposed decision to deny was issued in April of 2018. SCE comments of proposed decision was provided on May of 2018. And then CPUC decision held the application open and directed SCE to supplement the existing record with additional analysis in August of 2018.

And just recently there was a data request and so we submitted the first data submittal on April of 2019 and we're estimating the second submittal to -- sometime in September/October later this year.

So based on the initial plan, we had an estimated in-service date of quarter four of 2021. But due to this delay, we're estimating the completion date to be quarter four of 2025.

So the second project is the Riverside Transmission Reliability project, it's a new 200 -- 230/66 kV substation. Basically provides a new 230 kV interconnection to the City of Riverside to address load growth and improve reliability. The status in the CPUC draft supplemental EIR was submitted in March of 2018, the deadline to submit comments was May of 2018, the final subsequent EIR was October 2018, and we're anticipating the CPUC final decision sometime in March of 2020. Based on that, we're estimating the completion date to be quarter three of 2024.

So we have two projects that -- transmission projects that assist and deliver renewables to the L.A. Basin. The first project is the El Dorado-Lugo and the Lugo-Mohave 500 series capacitor upgrade project. As the name implies, we're upgrading the series capacitors on the two 500 kV lines, which in essence help deliver power in to the L.A. Basin. So this project expands from San Bernardino County all the way up to Clark County in Nevada.

The CAISO approved this project in its 2012/2013 CAISO TPP, so I guess the El Dorado-Lugo 500 kV line series upgrade was approved in the 2012/2013 TPP. And it was approved as a policy driven project and subsequently Lugo-Mohave 500 kV line was approved in the 2013/2014 CAISO TPP.

The CPCN was -- will be submitted in April of 2020 and we're anticipating construction start date in March of 2020. Based on that, we're estimating the completion of the project to be quarter two of 2021.

So,the second project is the West of Devers 230 kV transmission line upgrade project. Basically in Riverside and San Bernardino Counties we're upgrading various 230 kV lines. And these upgrades are required for the deliverability of renewable projects in the area.

The CPCN was issued in August 2016, the BLM record of decision was approved in December 2016, started the construction in January of 2018. Based on that, we're anticipating completion of the project in quarter four of 2021.

So we'll go to the third category which is related to the local capacity requirement. For the first project is the Santa -- in the -- sorry in the Moorpark Goleta area, it's the Santa Barbara County Reliability project which upgrades 66 kV lines between SCE Santa Clara and Goleta substations to address the loss of the 220 -- 230 kV lines that serve Goleta. And this project came online just recently in April of 2019.

The second project, the Moorpark-Pardee number four line was proposed to address what you see retirement of Mandalay Bay, and Ormond Beach generating plants. And really, it's stringing of four circuits on existing towers. This project was approved in the 2017/2018 CAISO TPP as a reliability driven project. Detail -- currently, detailed engineering is underway, we hope to start construction later this year, quarter three of 2019, and based on that, we're targeting a completion date of quarter four of 2020 to meet OTC compliance.

And the last project is the Mesa 500 kV substation project in the western L.A. Basin. This is -- the project was also required to support retirement of OTC generation, particularly Redondo Beach, Huntington Beach, and Alamitos in the western L.A. Basin, approximately 3800 megawatts of generation and this was to loop in the existing Mira Loma to Vincent line into a new 500 kV substation. The PTC was issued in February 2017, we started construction in October of 2017, and the latest date that we have for the estimated completion is March of 2022.

Just to touch on what Neil had said, we realize that this is an important project, talked to our project manager and they are looking at various ways to perhaps meet an earlier date, but there’s too many variables at this time and we’re the -- committing to a March 2022 date.

That’s all that I have, if anybody has any questions.

VICE CHAIR SCOTT: I think like the last panel, unless there’s any burning questions, we’ll let all the panelists speak and then we’ll do questions from the dais.

MR. LEE: Good morning, Commissioners, my name is Gene Lee, I work in Southern California Edison’s Energy Procurement Group.

I just have a few slides today. We’ll be talking about a couple things. First off, a recent solicitation that we completed named the 2018 LCR RFP that was specifically a procurement activity for the Moorpark area which is -- sort of straddles the Ventura and Santa Barbara County up in the

Los Angeles Basin's northwest coastline area. So as I stated, we completed that recently so I'll go over the results for that and then just provide generally an overview of SCE's preferred resource energy storage procurement to date which has been, I like to think substantial.

So the LCR RFP, as I noted, was a targeted local capacity requirement's procurement activity in the Moorpark area. Specifically, we were targeting two A-bank substations the Goleta and the Santa Clara Substation as areas of need -- as areas of need identified. We had additional objective to enhance a resiliency effort in the Goleta system, the Goleta A-bank Substation specifically is near the end of the transmission system and is therefore little more -- can be affected a little bit more by outages in the particular area.

So the procurement activity took probably the better part of a year. The portfolio that we wound up with and are currently going through the contract approval process for was basically 195 megawatts of battery-based energy storage resources. This is not uncommon, this is in line with what we've been seeing with a lot of procurement activities that we've been doing as of late.

Along the bottom you can see sort of a flow chart of the various resource mixes. As the procurement process went on, it kind of winnows down over time. We did receive offers for other resource types besides in front of meter storage, there were gas offers received, other preferred resource types such as demand response for EE, not as much as an amount. And then overtime as we winnow down the portfolio looking at pricing and viability, it became increasingly more a storage basically procurement activity.

And so this table actually shows the contracts that were executed by the SCE as part of the solicitation. It shows basically the developer, the name of the project, the resource type, which basically in this case just delineates whether the project was in front of the meter or behind the meter. There was one behind the meter project, the contract with Swell, which essentially they're installing customer-based -- customer sighted storage sort of dispersed just through the area, capacity and the commercial online date, the nominal online date being June 1st of 2021.

So the Moorpark activity was probably our largest and most recent activity. Just wanted to discuss some of the other preferred resources storage procurements that we've done. So LCR 2018/2019 which I just discussed and we actually started out in 2013 which was also the genesis for some of the repowers that were discussed in the previous panel.

Several years ago we instituted a preferred resources pilot. We were attempting to procure DERs specifically in the Orange County area. To this point, we've run two Aliso

Canyon energy storage specific solicitations that was to address the operational issues due to the shutdown at that particular facility that was storage specifically.

We continue to do RPS procurement to attempt to meet RPS requirements and REC sales basically to meet those compliance targets. In addition, we've undertaken some specific distribution deferral for distribution liability, preferred resource and storage procurement activities, that's a relatively new occurrence. And we have a host of smaller program tariffs that we run which are generally meant to submit -- to meet policy goals that are ongoing.

And so there are a number of activities that we have out there for preferred resources and storage. I would say as of late as I noted previously, the energy storage has been probably the predominate technology that we've seen and has also has been the most attractive from a solicitation standpoint.

So this table lists basically the storage procurement that's been done probably starting since 2013 or so. You can see it's also bifurcated by essentially the domain that the storage is in, whether it be transmission, distribution, on the customer side. Fairly well balanced and it amounts to roughly a little over 100 -- 700 megawatts procured by SCE.

Oh, I think that's my last slide. Thank you.

VICE CHAIR SCOTT: Thank you.

We'll go on to David.

MR. THAI: Good morning. My name is David Thai, I'm with the Origination Organization at San Diego Gas and Electric, and I'm pres -- looks like our presentation's not up yet so.

MS. ACEVES: Maybe I'll ask Gene a question while we're waiting. Okay. For your Swell storage that you mentioned.

MR. LEE: Yes.

MS. ACEVES: Does that include dispatch rights?

MR. LEE: It does include dispatch rights.

MS. ACEVES: Okay. And the SGIP amount over a hundred megawatts, how are you accounting for that? Is that just load reduction or are you accounting for it in any sort of flex or not at all?

MR. LEE: When you say accounting for it, as far -- could you maybe rephrase possibly?

MS. ACEVES: How are you accounting for it in meeting any of your demand needs?

MR. LEE: Yeah. So I mean it gets folded into the various planning processes as storage that is available. Exactly how it gets flowed through the IEPR process, for example, I'm not a hundred percent sure exactly but it is accounted for when we talk about the residual demand.

MS. ACEVES: Okay. So just on the demand side?

MR. LEE: Yeah.

MR. THAI: We'll try that again. All right. Hi, my name is David Thai, I'm with Origination Organization. I'm presenting on an update on the Encina Power Plant decommissioning status, an update on the Carlsbad Energy Center, and SDG&E's preferred resources procurement.

As mentioned earlier, back in 2010 the California State Water Resources Board had approved the once-through cooling policy facilities like the Encina Power Plant needed to meet these new OTC policy requirements or cease operations. The original date for Encina Power Plant's retire -- compliance due date was December 31st of 2017. It was subsequently modified to December 31st of 2018 in August 15 of 2017 due to delays in the Carlsbad Energy Center Power Plant's development. Effective December 11th of 2018 Encina retired, they're currently going through their decommissioning process. We expect that to conclude officially Q4 of 2021.

As mentioned in the prior slide, Carlsbad Energy Center's became comer -- Carlsbad Energy Center's became commercially operational December 12th, this was critical to ensuring Encina Power Plant could be decommissioned due to reliability issues. This is a 500 megawatt gas fire facility approved by the CPC on May 21st of 2015. The image to the right shows the 5 GE LMS 100 units, four of them stacked together, of which is com -- Carlsbad Energy Center's comprised of, to the right side of that image you can see the legacy Encina Power Plant.

In terms of -- next slide -- in terms of preferred resources procurement, SDG&E launched a solicitation in 2016 for preferred resources in its local area. We received -- ended up contracting with six different counterparties for five energy -- battery energy storage projects, one demand response project. We submitted an application 1704017 of which received approval April 25th of 2018, approving all approximately 88 megawatts of capacity. And as you can see in the table, there's the listed resource name and expected online dates.

Finally, we wanted to include a slide on the Integrated Resource Plan given that's going to dictate and drive future preferred resources in San Diego's area to meet the state's goal of decarbonizing the system but doing so such that we don't -- do not jeopardize reliability and make cost effective decisions.

To the right side of this slide, you can see a bar graph that illustrates we'll need 12,000 megawatts of wind solar preferred resources by 2030 to meet the State's GHG reduction targets of 42 million metric tons. SDG&E will be contributing to this effort by means of distribution of estimate of deferral frame work solicitations and GTS are green tariff shared renewables solicitations to name a couple.

That’s all I have. Thank you.

VICE CHAIR SCOTT: Thank you.

We’ll hear from Jason.

MR. RONDOU: All right. Good morning. My name is Jason Rondou, I’m manager of Strategic Development and Programs at LADWP and I’m going to present on LADWP’s recent news around once-through cooling and some of our accelerated renewable plans that were announced recently. Touch on how that’s going to impact our transmission planning process. And then a wrap up with some of our preferred resources just to resource plans and how that’s going to change in the near future.

So starting off here, many of you are aware of this but in February it was announced that the three coastal generating stations that have once-through cooling units remaining at them, that the city of Los Angeles and LADWP would not be reinvesting in repowering those units.

And so that doesn’t mean that the plants will be shut down by 2029 or 2030, it means that the units that were slated to be repowered and get off of ocean cooling, would not be repowered as we had previously planned to do.

And to give some context on this, about two years ago, we initiated a study that looked at what could we do as an alternative to that repowering. So looking at local storage, local transmission, large scale transmission as well -- or sorry, out of basin transmission as well, and utilities scale resources. So a mix of what could replace that nearly 1660 megawatts of natural gas.

And so what that did is we know that, you know, the goal here is 100 percent by 2045, that simply took one path there off the table. And so in addition to that, last month the Mayor released the sustainability plan which was also titled "The Green New Deal" for Los Angeles.

And one of the significant items here is the acceleration of renewable energy by 2036. And you see in this graphic here 80 percent by 2036. And when you factor in other non -- technically nonrenewable resources, that's actually 96 to 97 percent fossil fuel free. And so that's a significant acceleration for us. And it's a major change in the way that we operate our grid and the way that we deliver energy.

In addition to that major goal, there was also some additional goals around building electrification and electric vehicle deployment. And so what that would mean for Los Angeles is for all new buildings by 2030 to be fully electric and then all buildings to be fully electric by 2050. On the EV side, the entire fleet of metro buses and buses operated by the city of Los Angeles would be fully electric by 2030 as well with the goal of a hundred percent transportation electrification by 2050.

So these are major pressures on the demand side but as well as the supply side as well. And so I'll talk about how that's going to impact a lot of our planning processes.

And so we had anticipating releasing an update to our strategic long-term plan this year, but with the change in plans that have arisen over the last several months, what that has caused us to do it is reorient our strategic long-term plan and align that with our 100 percent renewable study that we're conducting with NREL at the moment.

And so what that will mean is, you know, we need to look at what are the resources that we need to deploy over the next, you know, five to ten years to replace that capacity and to replace that energy. And at the same time, we don't have the luxury of waiting until the end of 2020 to start getting to work on a lot of these plans. And so what we're doing now is identifying sort of the low hanging fruit and the sort of no regrets transmission in DER projects that we can do over the next several years to help bridge that gap.

So jumping into the transmission slide here just to give a little bit of an overview of our system. Significantly, I'll start talking about this -- the piece labeled D and as you'll see the red line at the top. That's our Owens Valley line. We bring in a massive amount of renewable energy and that is actually growing at this point as well. Just to the left of that is our PDCI, Pacific DC Intertie line that comes in and provides energy down to the Sylmar portion as well.

And on the left-hand side we have our Vic-LA, or Victorville/Los Angeles line that brings in, again, a significant amount of energy as well into the L.A. Basin. And the rest of the lines here are local transmission.

And so, what the recent news means for us is a potentially significant growth in -- to the degree of hundreds of miles of new transmission both on the local level in basin but also at the large-scale level as well.

So in addition to that, and I'll touch on this a little bit later, going down that path of accelerating the deployment and to the expansion of transmission lines, we need to simultaneously redouble our efforts on the distributed energy resource side. And again, I'll talk about that in a moment.

So talking about some of the recently completed projects here on the transmission side. So we recently completed the Barren Ridge transmission line upgrade which allows us to bring over 1000 megawatts of renewable energy in the basin here and we've got another 100 megawatts that's actually coming in later this summer.

And I'll talk more about this later but we're currently wrapping up negotiations on a large-scale solar and storage project that will provide a little bit more flexibility here. And so what we're doing, what you're seeing here is that we're leveraging this existing line into the city of Los Angeles but one of the tradeoffs that we have is the geographic diversity. So you see a substantial amount of solar and renewable resources all coming in on this one single line and so that's where this next upgrade that we've got slated becomes increasingly important.

And so to mitigate that geographic diversity loss that we have of bring on -- bringing in all of this renewable energy, we're planning to upgrade this to 1700 megawatts of capacity to come in to the city of Los Angeles by tying in Castaic and allowing that pump storage resource to help mitigate some of that, you know, intermittency as well.

And to I think most of you are aware of this, but for those of you who are not, the city of L.A.'s peak energy usage is 1600 -- sorry, 6400 megawatts of energy of peak demand. And so when you're talking about 1700 megawatts of renewable coming in a single line, that's a substantial piece.

In addition to that, we are looking to upgrade our Vic-LA path as well. So when you talk about bringing in mass amounts of utility scale renewables, we need to be able to create the capacity to actually bring that in to Los Angeles to actually get that home. And so over the next couple of years we're going to be upgrading out Victorville/LA path to be able to do that.

In addition to that, we are looking to leverage these existing resources that we have here. So we have another over 600 megawatts of capacity to bring in via the transmission lines that currently connect to the Navajo Generating Station location. So you can see the transition from fossil fuels to renewable energy, we've got a great opportunity here at Navajo as well to bring in those renewable resources.

Similarly at Mohave we also have the ability to do that to the tune of 700 megawatts of renewable energy as well.

So moving along quickly here. Some of the more longer term things that we're looking at is on the Victorville/LA path looking at high voltage AC or DC and again, that's going to allow us to bring in even more renewables.

On the Southern Transmission System, currently we're bringing in coal energy through that transmission line but as we transition to renewables here, it would allow us to bring in potentially over 1,000 megawatts of renewable energy. And so again you're starting to see a little bit better geographic diversity of those renewable resources that come in. And along that line we'll also be looking at potentially compressed air storage as well that will help mitigate some of that intermittency.

So moving on to the distributed resource side. So in light of the news that came in in February about not repowering as well as the accelerated renewable targets that -- accelerated interim renewable targets, we recently released a distributed energy resources RFI where we are looking to the industry to bring in ideas on how we can mitigate the loss of that local in basin generation, again 1660 megawatts of in basin generation. So those responses are due mid-June. There's a possibility that we extend that out a little bit but we do expect that to close in June. And then subsequent to that, we'll evaluate, we'll look at the different proposals and then we'll issue subsequent RFPs shortly thereafter.

And kind of touch on some of the recent accomplishments on the local solar side. And so you'll see a graph here that is going to change with the news that we're going to accelerate renewables. These are graphs that are from our last year strategic long-term plans. So quickly going through this, we've got about 350 megawatts of local solar in the city of L.A. right now. We're recognized as the number one city for solar in the country and that's largely due to a mixture of our local portfolio of renewable solar programs.

Our Feed-in Tariff program which is a strategically important program for us, where we're purchasing energy, power purchase agreements from customers in basin and so this will allow us to achieve renewable energy credit as well as reach our renewable and in basin solar goals. We also have a growing portfolio of community solar programs as well. So we recently just launched our shared solar program where we're allowing multifamily customers to subscribe to solar rates that will help provide fixed rate for their energy over the course of ten years. So for customers and customers that can't afford to go solar or don't have a roof or don't have a suitable roof, we have a growing portfolio of programs for them as well.

And as we go down this path of 100 percent renewables, the cost of that transmission is making equity obviously a significant portion -- significant consideration for us as we go down that path, especially for the distributed resource programs.

On energy storage, I'm going to quickly go through this and talk about a number of the distributed energy resource energy storage projects that we have sponsored. We've done installations, microgrid installation at a fire station up in Porter Ranch. At our La Kretz Innovation

Center we have a solar installation as well, but notably we at our headquarters in downtown Los Angeles we're installing two different technologies of batteries, lithium ion and the flow battery. And in addition to that we've actually got solar to date in there and it's an old system that's actually generating energy pretty well now, it's about 19 years old.

We also have about 260 EV chargers and so that's the public fleet as well as employee charging as well. And so what's -- what that's allowing us to do is, you know, pilot and demonstrate an energy management system which we're going to deploy in the future to help balance that load and balance that generation. And that can be a lesson for us and for customers to be able to model a future where we can balance that and actually control those resources.

We're actually partnering with many different city agencies as well. So we actually just started design and construction on -- well, procurement and construction will start this summer at different recreation and parks facilities. And so these are strategically important for the department where we've identified cooling centers in areas that would be potentially most vulnerable in the event of an extended grid outage to provide resiliency and a cooling center for those customers in those areas.

And we're also looking at potentially install -- installing solar and storage at the Los Angeles Zoo and that would be a potentially very large-scale microgrid installation as well.

And I mentioned this earlier and I've got it up here again, that we're currently negotiating a power purchase agreement for solar and storage that would be likely well over 100 megawatts of four-hour storage here as well.

And so to give a little bit of scale on that one, this is our 20-megawatt beacon battery storage project that we completed this past year. This is a half hour battery and so the installation that -- or the contract that we're currently negotiating would be potentially 100 times larger than this in scale so that gives you an idea of the scale of project that we're looking at.

Moving on to demand response. Historically we haven't had a very robust demand response portfolio. In part, we haven't need to have one but as we transition to a more renewable future and a future reliant on distributed resources, the need for growth in this DR portfolio for Los Angeles is becoming increasingly important. So we actually just recently increased our incentives for commercial and industrial customers by 50 percent, and next year we're going to launch a residential thermostat project as well.

And these targets are very likely going to grow as we study the need for renewable -- distributed resources over the course of next year with our 100 percent renewable study.

Moving on to electric -- transportation electrification goals. So I mentioned that there's the longer term goal of 100 percent by 2050, but the interim goal is 145,000 electric vehicles by 2022. And so we're trying to achieve that through a portfolio of different approaches.

And so most notable we just almost tripled our -- well -- our used car rebate for the city of Los Angeles. So we've got a proposal to our board for consideration to go from $450 and up to $1500 for used EV chargers. And so, again, this gets back to, you know, our effort to have equity as a central consideration when we deploy our distributed energy resource programs as well. We continue to offer our EV charger rebates as well as our substantial commercial chargers.

We also partnered with the city on a blue L.A. car sharing program. And so what we're trying to do here is target disadvantaged communities and other communities that don't have access to renewable -- excuse me, to electric vehicles and electrical vehicle -- electric vehicle charging. So this is a fully electric fleet of cars that are available to our communities in public settings.

We also are targeting pole-mounted chargers as well. So these are actually on street, you can pull up to a curbside parking stall and actually charge your electrical vehicle as well there. And we again, you know, finally to round this out, we continue to partner with city facilities as well as LADWP facilities to continue to deploy publicly available chargers as well.

And I'm going to finish here on energy efficiency and to avoid going through the detail here, the point and the takeaway from this chart is that we have had a very substantial growth over the last two years in our energy efficiency budgets and this is not just budgets, this is just the actuals that we've actually been able to achieve.

And so the significance here is that we've had historically had a very comfortable and very large budget for energy efficiency but our ability to deploy that has grown substantially. And part of that was an acceleration to many of our portfolio programs that started back in 2016 as a response to the Aliso Canyon shutdown. And so you can see here a portfolio of residential as well as commercial programs that we continue to provide and we will also be conducting a renewed potential analysis -- a potential study to determine how we can potentially expand our EE targets as well.

And finally, here we -- this past several months -- last month, we completed a study with SMUD and with SCE on electrification which will result in us incorporating electrification targets in our strategic long-term plan and working with the city of Los Angeles Building and Safety

Department to incorporate electrification incentives and codes for our building codes.

So with that, I'll take any questions that you may have.

VICE CHAIR SCOTT: Great. Thank you. And thank you very much to all of our panelists.

Maybe I will start with Commissioner McAllister from afar. Commissioner McAllister, do you have any questions for the panel?

COMMISSIONER MCALLISTER: Really, I just wanted to congratulate DWP on the kind of the ramping up of those initiatives on energy efficiency and really want to collaborate however possible and appropriate on the demand response side that you brought up. I think that has a lot of potential as all of you know a big booster.

I think we can be doing a lot more sort of targeted demand response and then figuring out how to do that well across the state. So, yeah, no questions for anybody, I might build on some other questions that you all have in the room but for now I'll be listening.

VICE CHAIR SCOTT: All right. Sounds good. Let me turn to the dais, Commissioner Rechtschaffen.

COMMISSIONER RECHTSCHAFFEN: Rabindra, could you go back and just talk a little bit -- you -- just to go back to the Mesa Loop-In project. You have a conservative estimate of when that's going to be in service, you don't want to commit to anything before 2022 but I thought I heard you say you're trying to speed up the in service date. So could tell us what you're trying to do to get that online sooner?

MR. KIRAN: Sure. So I talked to the project manager of -- for the Mesa 500 kV project and they're looking at reevaluating the bids for the upcoming phases of the project and to see if there's any synergies there that they can expedite or meet an earlier date. I think that's part of the construction. When I talk -- when say phases, that's part of the construction phases that are happening for the Mesa project. I think we're in Phase 2, there's a Phase 3, Phase 4, and Phase 5. And I think they're going to reevaluate the bids.

COMMISSIONER RECHTSCHAFFEN: So is the -- I'm just -- I'm trying to figure out what the constraint is. Is it just getting someone to do something more quickly? It's -- you have all the approvals, it's just having the construction completed more timely or what is the limiting factor?

MR. KIRAN: Well, I think it's just the delay. I think there was a one-year delay approximately in the licensing phase of the project. And it just pushed out our initial June '21 date to a March '22 date. I think it's just the time it takes for the project to get done. And we are looking to see if we can expedite that.

COMMISSIONER RECHTSCHAFFEN: Okay. I had a question for Gene but if anyone -- I don't know if people want to follow up on that.

VICE CHAIR SCOTT: Can I do a follow up to Rabi as well.

I was, yeah, I was noticing on your last slide in the presentation, the timelines for the three lines that you had mentioned, and they were under two years except for this last one. And so I was also wondering -- trying to get a little bit more insight -- oh, thank you for pulling that up. So the Santa Barbara one, had -- I don't know what is that about 18 months or so between construction start and when it went online. And then you're anticipating about year and a quarter for the Moorpark one. And -- but this one started in October 2017 but is all the way out at Q1 2022.

And so if you do have some additional information on to provide some granularity on to what is causing the hold up between -- on this one.

MR. KIRAN: Sure. The Santa Barbara project, Marty-Pardee -- sorry, the Moorpark Pardee Number 4 line is a pretty simply project. We're just stringing a second circuit on an existing -- already existing transmission line.

The Mesa 500 kV substation power is pretty significant. We're building a brand new 500 kV station. We're rebuilding the 230 and the 66 kV racks, so I think that's were a lot of it -- it's a significant project.

COMMISSIONER RECHTSCHAFFEN: Thank you.

VICE CHAIR SCOTT: Back to Commissioner Rechtschaffen.

COMMISSIONER RECHTSCHAFFEN: I was going to ask Gene a question about the Moorpark solicitation. And you explained that your slide show that you had received only an immaterial number of bids from renewable companies and then the gas fired resources fell out through the procurement process and ultimately selected in front of the meter storage and then one behind the meter project. Were there other competitive in front of the meter storage proposals that weren't selected?

MR. LEE: There was a lot of in front of the meter storage that was provided and so I guess it depends what you mean by competitive. We were just striving to select the best ones to meet the need. I suppose you could say that there were other competitive ones that had the need been larger, you know, that we would have went ahead and procured as well.

COMMISSIONER RECHTSCHAFFEN: That's the question. Were there other viable bids that were close or that would have made it if you -- if the procurement need was greater?

MR. LEE: Yes, I would say so.

COMMISSIONER RECHTSCHAFFEN: And then could you just remind us how you distinguish resiliency from reliability and what additional need was served by this project?

MR. LEE: So the resiliency aspect was really just for the Goleta subarea and the Goleta substation. The reliability requirement is fairly well defined by folks here and by the Commission and by all entities. Resiliency requirement is not as well defined and is specifically not a requirement per se for procurement activities that we do, although it is something of a concern.

So strictly by the LCR requirements, the first task was to meet the reliability need in the area. The resiliency need essentially defined by significant outage -- transmission outage in the area. Specifically there are two major transmission lines that feed the Goleta substation and if both of those went down, that there would be potentially sustained outage in the Goleta area. It was something that we were targeting and during the optimization and some of the resources that we procure will assist with that resiliency effort but they won't necessarily provide 100 percent resiliency coverage if there was an extended transmission outage at the Goleta substation.

COMMISSIONER RECHTSCHAFFEN: Okay.

MR. LEE: Okay.

VICE CHAIR SCOTT: Mark.

MR. ROTHLEDER: Yeah. Jason, two questions. One is as you know, I've adopted the sustainability clean plan. It wasn't clear if it has an effect on the OTC retirement dates and -- or not.

And then the second question is, on the PDCI, the DC Intertie, is there progress underway to make that a more flexible scheduling capability so it can actually be responsive to variability and intermittency of resources and load?

MR. RONDOU: Yeah, so on the first part of that, I'm not aware of the -- any efforts underway that -- it's possible that there are on the PDCI piece. On the first part -- can you remind me again on the first piece of that?

MR. ROTHLEDER: No, it just -- it wasn't clear if -- now that you're not doing repowering will --

MR. RONDOU: Whether or not the plan actually --

MR. ROTHLEDER: Yeah.

MR. RONDOU: Yeah. Yeah. So it actually kind of came in two -- two pieces. The first was in February where there was a press event that, you know, had the announcement. And the announcement was that there would be no repowering, there would be no investment in new gas for those units. Subsequent to that in April or I believe late April, the sustainability plan more codified that from the mayor's perspective, meaning specifically what the interim renewable goals were and then subsequent to that there was specifics about, you know, OTC, there were specifics about building electrification, and all of that.

The next step for us is to take that into consideration as we do our strategic long-term plan. And again, that would then look at now, from the high level build down, what are those resources and all of that. And typically we do that every single year and we planned to do it this year but given that that news and that information came so recently, we simple don't have the ability to launch complete that this year and actually do a thorough study of all the costs and all the resources that are necessary.

And so, we elected to do is move that to the end of next year, combine that with our 100 percent study and release both of those at the same time.

So, yeah, the plan did touch on the OTC issue as well.

VICE CHAIR SCOTT: Other questions from the dais? Oh, please, go ahead.

COMMISSIONER RECHTSCHAFFEN: Jason, the 1700 megawatts of renewables that are going to be facilitated by the transmission upgrade or the 1000 that are there now, are they -- is that from California or is that a combination of imported resources and from California?

MR. RONDOU: So the short answer is we don't know. We had previously, over the course of the last year conducted a study that looked at about a dozen different cases of repowering from floor repowering of the 1660 megawatts to no repowering. And the two no repowering cases had varying levels of emphasis on transmission and distributed resources. But the bottom line is it took a significant amount of both to be able to replace that 1660 megawatts.

The outcome of that again, well -- the details of that would be available at the end of next year, but I can tell you that with all likelihood that the lion share of the utilities scale and local -- I mean, obviously the local would be, you know, California renewables.

But there would be a substantial amount of California renewables as well. But the long story short is we don't know, given a rough order of magnitudes, it's probably going to take a couple hundred mega -- couple hundred miles of in basin transmission as well as a couple hundred miles of out of basin transmission. The order of magnitude for local storage is not utility scale but in basin storage is likely between 1000 and 2000 megawatts of local storage -- energy storage.

VICE CHAIR SCOTT: Great. Other questions from Commissioner McAllister?

COMMISSIONER McALLISTER: This is Commissioner McAllister.

VICE CHAIR SCOTT: Oh, go ahead.

COMMISSIONER MCALLISTER: Yeah, I have one more question. Actually, you started to talk about it just now, this is for Jason.

You mentioned and talked about the out of basin, you know, so the import, the sort of bulk energy import transmission upgrades that you need, you know, Vic-LA and what's coming from out of state. You mentioned also that you would need in basin transmission, you know, I guess presumably to the 231/38 kV system. Have you had long enough to think about what that might look like? I think you just said a couple hundred miles but maybe give us a qualitative view of what that might look like.

MR. RONDOU: Yeah. Again, I think the very, very high level challenge that we have is we've got substantial amount of ability to import energy on the northern side of the city of Los Angeles. And a lot of the energy that's provided on the southern side is provided via our Scattergood, Haynes, and Harbor Stations, which again, has the 1600 megawatts of OTC units. And so for the ability for us to continue to balance power for power flow considerations, we need to be able to bring and generate energy on the southern part of the city.

And so what that means is, you know, are we going to be able to do all that with distributed resources, you know, a big portion of it will, but to be able to bring energy where we need it in our service territory, it will require a substantial amount of in basin transmission upgrades and potentially new transmission lines.

And so, you know, that process obviously comes with a substantial amount of risk and consideration for, you know, the development of transmission lines. And so when you talk about going down the distributed resource side and the transmission side, you really -- we're going to have to go down both of those paths kind of simultaneously and factoring in the likelihood that there will be delays on, you know, all sides of that equation. So substantially more to come on that but at a very high level, that's the background on the need for the in basin transmission.

COMMISSIONER MCALLISTER: Thanks. Thanks a lot.

MR. TISOPULOS: Just clarification. So you mentioned you are going to be -- you'll have to rely on importation and it's a little bit foggy, we understand that. I was wondering out of curiosity, are these going to be LADWP owned renewable generators or not necessarily or a hybrid mix?

MR. RONDOU: Yeah. Historically, we've owned or controlled the vast majority of our resources. The, you know, the growing exception to that is power purchase agreements for utility scale renewables and the reason for that is, you know, the investment tax credit and all the other private sector, you know, tax advantages of doing that.

We do typically factor in buyout options to where we could potentially exercise those at, you know, at various dates that are advantageous to us. And we very likely continue -- will continue to see some of that.

On the distributed side, that gets a little bit more complicated, right. The opportunity and the necessity for partnerships on the distributed side is going to be substantially higher than it would be for the utility scale.

MS. ACEVES: I have a question for both Jason and Gene, have either of you been partnering with either with each other or with the clean power alliance on any joint generation or transmission projects?

MR. RONDOU: I am not aware of collaboration for transmission projects. There is that possibility but I'm not aware of any. On generation, I don't think there is, usually when we collaborate or partner on a utility scale generation, it's with other municipal utilities locally in Southern California.

It's possible that there is something but I'm not aware of it and I don't think there is.

MR. LEE: I'm not aware of it either although Jason seems like a very nice individual and I'd be open to that.

MS. ACEVES: There with clean power lines?

MR. LEE: No, not to my knowledge?

VICE CHAIR SCOTT: All right. Well, I want to say thank you very much to our excellent and informative panel. We are just a few minutes ahead. I only have one blue card here with me and so I was going to check to see, Mr. Nagim, if you are here in the room, would you like to go ahead and make your public comment now? You are also welcome to wait until after the -- until we get to the public comment period at the end of the day.

MR. NAGIM: I will wait.

VICE CHAIR SCOTT: Okay. All right. Well, so we will then go on our lunch break, please be back promptly at 1:00 p.m. sharp. Se you all then. And thank you again to our excellent panel.

[Off the record at 11:46 a.m.]

[On the record at 1:00 p.m.]

VICE CHAIR SCOTT: All right, everybody, it's 1:00. We're going to get going again so please take your seats. We have some excellent panels for this afternoon. Our Panel Number Three is going to be An Update on Reliability and Other Issues Associated with SoCalGas Infrastructure Challenges. And they are here, let me -- we'll start with Simon and get his presentation queued up.

MR. BAKER: Good afternoon, Commissioners.

VICE CHAIR SCOTT: Welcome back.

MR. BAKER: So as we've done in past years, the PUC staff did a look back at the winter to see -- what we saw on the system. And there's a report that we publish that's available on the Energy Commission website as well on our website. So I just wanted to go over some of the main findings of that report.

So as we've been saying the pipeline capacity is still a major constraint and was this past winter. We also saw very low temperatures particularly in January and February and early March. Storage inventory was down significantly and most notable the non-Aliso fields were down by 61 percent.

We saw receipt point capacity utilization much higher than historically average in the January, February, March periods. And Aliso Canyon had withdrawals on 37 gas days.

SoCalGas's demand response program was called 24 times and we saw natural gas prices spiking at the SoCal CityGate which happened during maintenance periods and periods of intense cold. And then we also saw the knock-on effects of those gas prices into the electricity markets where those spiked as well as a result.

So this slide shows for January and February gas deliveries which is in blue, and gas receipts which is in green, and then gas withdrawals which is in yellow there. And the difference between the deliveries or the send out and the receipts, that's what was met with storage and with line pack. There was actually a period on the system where storage was being utilized and in order to maintain reliability, the system needed to use line pack to meet that demand.

Through most of January and February deliveries exceeded receipts and this was of course largely due to the cold weather. Interestingly, the weather models were far off this year and what this does is it causes customers to schedule their gas deliveries perhaps inaccurately causing challenges for the gas operator to maintain its stability of the system.

The Natural Gas Institute issued a report that points to climate change as being one of the drivers of the difficulty of forecasting. And there was also a period when the Natural Weather Service was down due to the federal budget shutdown. It was also one of the coldest winters in history. So the high temperatures didn't reach 70 degrees for 41 consecutive days in downtown Los Angeles, and there were record lows as well in the cities of Woodland Hills, which reached 30 degrees; Burbank, 35 degrees; and Long Beach, 37 degrees.

As a result, there was very high demand for gas and that peaked on February the 6th, where peak hourly send out reached 5.7 BCF per day. The chart here shows a comparison of the temperatures this past winter in blue and the historical average in yellow there. And the blue box there shows the February period where the temperatures dropped significantly.

It's the high peak hourly send out that causes steep intraday ramping and this really put significant strain on the system and SoCalGas needed to call, what are called operational flow orders for all but one gas day from the period of February 4th to the 23rd.

Turning to the storage inventory, looking at the table here, we can see that total storage inventory began in November at 77 and declined over a period of time until March where it reached 38 BCF. SoCalGas has been doing winter technical assessments ahead of the winter and they established a monthly end minimum inventory levels per field. And this became important in managing the gas supply throughout the winter.

And SoCalGas was compelled to withdrawal gas from storage on 27 days in January and every day of February. And the chart shows the significant drop in storage inventory levels in particular from the Aliso -- non-Aliso Fields which dropped from 69 percent to 32 percent.

Looking at receipt point capacity utilization, we saw a trend to be expected which is as temperature dropped system capacity utilization tended to increase and the converse as well. The blue line shows pipeline capacity utilization, and the yellow line is the temperature.

And in January, the average receipt point utilization was 91 percent and February it was 94 percent and this was higher than historical average of 85 percent.

So Aliso Canyon was used significantly to get through the winter, it was the longest duration and highest volume of gas withdrawn from the facilities since the October 2015 leak. And as noted earlier, there were withdrawals on 37 gas days resulting in approximately 14 BCF withdrawals. SoCalGas issued its demand response programs and called those 22 times on Aliso withdrawal days and 24 times total.

And the contributing factors to the use of the Aliso Canyon facility was the heavy withdrawals from the non-Aliso Fields that occurred in the days prior. This is pursuant to the Aliso withdrawal protocol to use Aliso as a last resort.

But as was noted earlier, the gas company was managing the system to minimum inventory level targets for each of the facilities per month. And so there was a point at which they couldn't withdraw any further from -- on Aliso Fields without compromising the system so then they then began to withdraw from Aliso. And all of this was significantly caused by high hourly send out during peak periods in the morning and in the evening.

One of the mitigation measures that has been used is voluntary and mandatory curtailment. And so we saw 14 voluntary curtailments totaling in 362 hours or 15 days, two curtailment watches where customers were told that they may be required to reduce their gas use if curtailment is issued, that happened do the -- during the two coldest -- the two cold snaps from February the 6th to the 8th and again from the 19th to the 21st.

There were two mandatory curtailments of electric generation again during those same two cold periods. And at that time, SoCalGas worked with the two balancing areas to curtail some electric generation. The volume of gas curtailed each day is not presented here because it's a confidential figure and overall PUC staff evaluated the impacts of this activity and found that the results are mixed for voluntary curtailments because electric generation is not a significant source of demand during the winter.

Looking at natural gas prices during this period in November and December, the first chart here shows that SoCalGas CityGate's prices spiked in -- on November the 15th and then again on December the 3rd and this was due to maintenance that occurred on the Wheeler Ridge zone.

And the next chart shows how gas prices again spiked due to cold weather. This was during the February 6th and February 20 cold snaps, and they reached 14 and then 26 dollars per MMBTU. We saw this also effect the PG&E system which spiked on February the 6th at 18 dollars for MMBTU.

And then this chart shows the effects on electricity prices during the month of February. So this led to the calling of Stage 3 and Stage 4 low operational flow orders by the gas company. Which then got incorporated into the bidding behavior of electric market generators on the CAISO system.

So we saw electricity prices peak throughout the state of California, the yellow line shows the SoCalGas CityGate gas prices, and the lime green line is the SoPath15, Southern California electricity market prices and you can see that they coincide and that they spiked during those two cold snap periods in February.

So the PUC has been implementing a number of measures to mitigate the reliability and the electricity pricing impacts that we've been seeing as a result. As was noted earlier by Commissioner Randolph, the PUC Safety and Enforcement Division and the Energy Division have been conducting regular oversight on the status of repairs, on Lines 235 and 4000 and others.

Another mitigation measure is to potentially modify the penalty structure of the SoCalGas operational flow orders. And a proposed decision has been issued for comment and is up for Commission vote on May the 30th with regard to that. Another measure is to consider modifying the core balancing rules for SoCalGas. Under current rules, core customers balance their gas burn to forecast rather than actual. But now with new automated meter infrastructure, there's the capability to balance to actual. And so the proceeding is considering whether to balance to actual. And this -- if implemented, this may reduce the number of operational flow orders that are called and reduce the system stress.

And then finally, potential mitigation measure is to consider revising the Aliso Canyon withdrawal protocol. Again because of the extensive use of storage to meet hourly peaks and steep ramps, which puts strain on the system, a possible revision could be to allow the operational flow order level to trigger Aliso withdrawals and this would be a way -- this may increase system reliability, decrease OFOs, and reduce electric generation curtailment.

It's important to clarify however, that this measure -- all these measures that are being here, these are really to address short-term reliability and pricing impact issues, and is in no way determinative of, you know, what the commission might do. For example, in the Aliso Canyon order instituting investigation there which is implementing SB380 and to make a determination on the future use of Aliso Canyon.

So the longer term questions are being addressed there for the PUC. And that's what I have.

VICE CHAIR SCOTT: Great. Thank you. We all --

we'll next turn to Lana, Brad, and Glenn, have a joint presentation together.

MS. WONG: Good afternoon. Again, this is Lana Wong with the Energy Commission. So the Aliso Canyon summer 2019 technical assessment, it's a joint agency assessment.

VICE CHAIR SCOTT: Lana, can you wait just one second, let me check that we're still connected on the WebEx, right. Okay.

COMMISSIONER MCALLISTER: Yes. We can hear you over here. We're back up.

VICE CHAIR SCOTT: Okay. Gosh we're echoing, but I hear it here that we're back up, so I'm sorry to interrupt. Please go ahead, Lana.

MS. WONG: Okay. Here we go. So it's a joint agency assessment with the Energy Commission, PUC, California ISO --

VICE CHAIR SCOTT: Hold on a one more second, let's see if we can try to get the echo off the system. Wait, did that just work? We just say it, it will manifest itself. Okay. Sorry, third time's the charm, Lana, please go ahead.

MS. WONG: Okay. Or is it me? Okay. So again it's a joint agency assessment with the Energy Commission.

(WebEx Announcement)

MS. WONG: Did we lose them again?

VICE CHAIR SCOTT: Let's just take a couple minute pause to make sure the WebEx is there and we'll get going.

MS. WONG: Okay.

VICE CHAIR SCOTT: Everyone stretch.

(Connecting WebEx)

VICE CHAIR SCOTT: That's a thumbs up. All right. We have the thumbs up. Thank you for troubleshooting that for us. We do know that it's a joint report.

Lana, please go ahead and take it away.

MS. WONG: Okay. So I'll be presenting with my colleagues, we've got a single slide presentation, about 24 slides and just to let you know we'll be bouncing around a bit between presenters in this presentation, and I'll just let them introduce themselves when it gets to their turn.

So this is a seventh in a series of assessments. And, you know, we heard earlier in the opening comments that it's the fifth workshop we've held and it's the fourth summer that we've been here. And the fourth summer workshop. We've convened since the natural gas leak at Aliso Canyon

And so in the summer assessment, we are looking at the risk to electric generation or EG given the pipeline outages and restricted operations at Aliso Canyon.

And then we're also looking at mitigation measures to reduce that risk. And in Simon's presentation you've heard a few of those. As part of this assessment we do an electric impact analysis where we calculate minimum gas generation required for electricity system. We call this MinGen so you might hear that throughout this presentation. So MinGen it's not a plan to curtail, it's a metric that really is letting folks know this is how large the electric gas system -- how large a curtailment it could withstand and still maintain reliability. Or in other words, it's a level that we need to stay above MinGen, and again, it's not a plan to curtail. So the full summer assessment is listed at the link at the bottom and comments are due June 6th.

So the assessment covers multiple topics and you'll see these as we go through this slide deck. So we'll be looking at an update on the SoCalGas system, the current status of the pipeline outages and projections for return to service dates. We'll also do a quick look back at summer of 2018 just to see how we did, but it is not as extensive as the winter look back that Simon presented or, you know, the report that the PUC produced on the winter look back.

We'll also look at our ability to meet a one in ten-year electricity peak demand day and whether there's a surplus or shortfall. And so this one in ten-year -- so what does that mean? It's basically looking at the warmest day that you'd expect to see over a ten-year time frame. So we might not see that type of peak this year or next year, but it's something that we plan to. It's a planning criteria.

So we'll look at that and we'll look at what I call an adjusted one in ten-year peak demand where we look at okay, if you bring the electric system down to MinGen, what does that do to that peak day demand?

Then we'll also take a look at gas balance that was conducted out through December and this is basically to provide a preview of a storage -- a potential storage inventory build-out for next winter. But I want to emphasize that the focus of this assessment is on the summer time period.

We'll also look at the new mitigation measures and the one thing that I wanted to point out is that up to this point, we really looked at mitigation measures that were focused on reducing electricity outage risk. But as we've seen, I -- in Simon's presentation and also at a January 11th workshop on natural gas prices, what we've seen is price impacts that these outages have had on the gas and electricity systems. So the mitigation measures, some of them are targeted at trying to mitigate that price risk.

And then lastly, we'll hear from the ISO and LADWP on some of the actions they've taken to mitigate risk.

Okay. Results. So what we're finding is that the base case results are showing that we have sufficient supply after July 1st but certainly with more outages, generation still faces some curtailment risk. So to walk through this slide, it's a snapshot of our results. The gray area presents the one in ten-year demand that I referenced earlier. So the first row is the one in ten-year demand at 3368 million cubic feet a day. And that demand has declined from the demand forecast that we were looking at in our last assessment. So that's one bit of positive news.

And then the -- I had mentioned what I had called an adjusted one in ten-year demand, if you bring EG to MinGen and we come up with 2806 million cubic feet a day, peak day demand.

And then in the blue body, that's essentially telling us what our supply is, we've got pipeline supply, and we've got withdrawal capability from storage, and we get what we call a projected supported demand or a system capacity number.

And the next body, the sort of light gray or white area, that's essentially taking the difference between here's our demand, here's what our supply is, what does that difference really look like? Do we have a shortfall or do we have a surplus?

And the columns across are essentially time periods that -- and we'll go through this in a little more detail later in the presentation about the timing of projected return to service dates of pipelines.

And so what we could see in the first column is that when we look at our supply and compare it to our one in ten-year peak day demand, we do have a shortfall in the month of June. So that's what's denoted in red.

Now, if we take EG down to MinGen, what you'll see is that okay, then the system is okay, and we don't have a shortfall. And so the other columns are just other time periods throughout the summer.

And so what's going on in this first month of June is you've heard about the outages and you've heard about Line 235 outage, but there's also maintenance activity that is going on, on the SoCalGas system.

And, you know, what Simon mentioned in his presentation, too, is that we've seen some of these price spikes occur because of incremental maintenance events on the system on top of these outages that are already in place.

So we identified Wheeler Ridge and so the price spikes from last summer, July, the price spikes that Simon mentioned in November, December, well, there was maintenance going on at Wheeler Ridge on top of that. And it might have only been for a few days. Like it might be an outage event that's a four-day event but it's just enough loss of capacity in that timeframe if it's a tight time period, like in July, we did have a hot weather event during that time period. Well, it could cause prices to spike.

But so in this June time frame, there's additional maintenance, hydrostatic testing on Line 2001 in the southern system and that maintenance event goes from March 15th through July 1st. And so what that means it's a loss of an additional 350 million cubic a day of pipeline capacity during that time period.

So another note about the numbers on this slide is it presumes 100 percent transmission utilization is available and utilized. And so what you could see is that we have a surplus after July 1st and that surplus shrinks and if we go to MinGen and we look at sensitivities at less than 100 percent transmission utilization, basically all the way down to 85 percent, we're still okay after July 1st. But it's the June time period that we would still have a shortfall at less than 100 percent utilization on the transmission system.

So what does that mean? How do you resolve that shortfall? Use of Aliso Canyon could be used to resolve that shortfall. And so part of the story that you'll hear today is that we may need to use Aliso Canyon this summer and especially if the peak day occurs in June, we may need to use it. Last summer Aliso Canyon wasn't used at all, but depending on when that peak occurs if it's in June, we may see use of it.

MR. BAKER: So again, the system remains impaired due to multiple pipeline outages. And just to go back in history a little bit, on October the 1st in 2017, Line 235 ruptured, burning the outside of an excavated section of Line 4000 which was immediately -- which is immediately adjacent. Line 4000 then returned to service in December of 2017 at reduced pressure and it’s been operating at reduced pressure since.

The Line 235 repairs are ongoing and they’ve been challenged by the discovery of new leaks during the repairs. And the last publicly -- published date -- expected date for the return to service of Line 235 was June 22, 2019 as of the kind of date of publishing of this presentation. But I believe that timeline has moved up, we may hear from the gas company on that in their presentation.

After Line 235 returns to service, then Line 4000 will be removed for remediation. And that line is then projected to return to service August 9th at reduced pressure and then at increased pressure by November the 1st. And I expect we’ll be hearing updates from the gas company as well on that.

Line 3000 returned to service in September of 2018 and it’s been operating at reduced pressure. My understanding again is, the gas company can clarify is that that will be coming back online full pressure sometime next year.

And Line 2000 has been operating at reduced pressure to 980 -- is that MCF? I’m not familiar with those units? Okay. So this just provides kind of a visual picture. The takeaway is that the overall receipt point capacity has been reduced by 720 MCF. And the kind of X's on the chart, they show you where the, so the yellow X on the right there, that's Line 3000, and the other yellow X is Line 4000, and then the red X is Line 235 which is out, and you can see that the combination of Line 235 and Line 4000 cause a bottleneck on the system.

So the northern system is reduced by 720 MCF and this kind of shows the breakdown of the receipt point capacity from both the northern and the southern zones and it illustrates that most of the gas is coming in from the northern zone and the location of the constraint on the system there with the red arrow.

So in the summer of 2018, lower demand and a number of operational flow orders that were called helped to limit the number of curtailments that occurred during the summer. It was a warmer summer, actually it was -- it was -- was it warmer or cooler?

MS. WONG: Cooler than.

MR. BAKER: Cooler than the prior two summers, excuse me, and so the demand did not exceed a 3.2 BCF which is kind of a -- previously identified stress point, a threshold for the system. The gas company did use more low operational flow orders to maintain the system in balance and that's shown in the table there at the bottom where all the various different -- a number of the different mitigation measures are listed out there with notices, and curtailment watches, the flex alert, electric generation local curtailment, and then the low operational flow orders, you can see they went up to 49 in summer of 2018 relative to 26 called in summer of 2017.

There was only one day where there was a request for voluntary electric generation curtailment, and there were no withdrawals from Aliso Canyon as was mentioned earlier. And the gas company worked closely with CAISO and LAPWD to shift generation whenever possible and use of imports was also key.

And as been talked about there were significant gas price spikes on certain days when additional maintenance was -- occurred on certain days at Wheeler Ridge.

MS. WONG: So this slide just shows the demand for the prior three summers. So the 2018 is in the black, and so what you could see is that it just was a milder summer than the prior two summers. And when I looked at the data, that Simon mentioned, they're wasn't any day over that 3.2 BCF that was previously identified as a sort of a stress threshold on the gas system. And really there were only five days that were above 2.8 BCF.

MR. BAKER: So one thing that's new is some new regulations from the Division of Oil, Gas, and Geothermal Resources that require what's called a shut-in twice a year for testing and inventory verification at gas fields.

And the shut-in, the length of it depends on the field size and the characteristics of the field. Honor Rancho was shut-in from April 1st to the 22nd and there was another two-week shut-in that's projected to occur this fall. And the takeaway is that when the facility is shut-in, it's basically closed for any injection or withdrawal activity.

Also, the SoCalGas storage integrity management program, again part of the DOGGR regulations. This is requiring conversion to tubing only for flow which impacts the withdrawal and the injection curves. And this has resulted in a lower maximal withdrawal capacity at Honor Rancho.

MS. WONG: Okay. So our overall findings for summer 2019, that reliability can be met. We have good news and bad news. So on the plus side of things that gas required for MinGen on our one in ten-peak day, is lower. What we've seen is a decline over the last few years. And when I looked at the data, I said, okay, MinGen has declined almost 500 million cubic a day since 2017, that's about 25 percent.

So in the morning session, you heard about the multi-pronged approach to deal with the unexpected retirement of SONGS and planned retirements of OTC. So when I think about the overall impact those efforts of adding preferred resources and transmission upgrades are coming to fruition and they also help with the gas issues that we're dealing with now. So MinGen is lower because of these transmission upgrades.

What I also noticed is that gas demand and electricity demand -- I mention the gas demand of 3.368 million cubic -- well, BCF -- BCF day that that is lower than the demand forecast from last year.

So on -- the bad news and on the negative side of things is that the pipeline outages continue. So unfortunately the pipeline situation is much the same as it was last summer. We'll go through some of the projections for return to service date but as we begin summer, and through much of the summer, these pipeline outages are expected to continue.

In addition to that, there are -- there have been new pipeline leaks detected on Line 235. So that's been unfortunate and has impacted the return to service date. So there've been numerous date slippages on the return to service date. And so some of us, you know, are beginning to wonder is this a new normal. So as I mentioned this is our fourth summer here and we've been dealing with constraints on the gas system over the last four years whether to Aliso Canyon or to these pipeline outages that, is this something that the electric system will need to adapt to?

The other thing about this summer is that non-Aliso Canyon storage fields are likely to be lower than last summer at this time.

So the end result is that Aliso Canyon may be used this summer as I mentioned, especially if a peak day occurs in June. So we went through some of the numbers, we could have a peak day in the 3.2 BCF range and what that means is that you do need storage withdrawals to meet your demand.

And so it the non-Aliso Fields are insufficient to meet the required withdrawal amount, Aliso Canyon will be needed.

So MinGen it looks achievable but again it’s not recommended and it’s just a metric that is something that it’s important for the balancing authorities, SoCalGas and just for folks to know what that level that we need to stay above is.

And so what we’ll probably likely see is continued use of OFOs. You heard Simon mention the metric from last summer. Last summer we saw OFOs increase and they’ll likely continue because we’re essentially in a similar situation. And then as we look at refilling inventory, the outlook is somewhat uncertain on refilling storage inventory for next winter.

So I mentioned the non-Aliso Fields. So we looked at current inventory, it’s about 22 BCF as of May 15th and last year we were about 28 BCF. And so what this means is that the lower inventory reduces the withdrawal capacity out of the fields, so if we don't have as much inventory, you won't be able to get as much out. And our gas balance projects that we'll have about 57 BCF by July 1st compared to 62 last summer.

So this slide goes through our results and we produced three cases, a base, pessimistic, and optimistic case. And essentially the difference is due to the return to service date of pipelines. And in the end, I mentioned the date slippages and the cases really in the end didn't turn out that much differently. I ended up making adjustments and in the optimistic case, that increasing pressure that Simon mentioned on Line 4000, we potentially could get an incremental 300 million cubic feet a day if that happens. Well, that's not projected to happen until November, so it doesn't impact the summer time period.

So we also have the 2018 numbers laid out here but pipeline capacity is in a similar range to last summer except for the month of June where that supply is lower due to that hydrostatic testing.

The storage capability identified, it's based on the midpoint between SoCalGas's summer 2019 technical assessment in their best and worst case. And so these numbers, what we say is that, it could be worse with more outages and maintenance. And so when I looked at SoCalGas's maintenance outlook, I saw maintenance scheduled at Wheeler Ridge, Honor

Rancho for the summer period so I just said okay, we need to watch for price spikes there.

MR. BOUILLON: Good afternoon, Commissioners.

My name is Brad Bouillon, I am the director of Regional Operations Policy and Analytics at the California ISO. Thank you for allowing me to speak today.

I'll be covering a couple slides and there's some breaks in between, so we'll be handling these transitions back and forth.

This first slide discusses the MinGen, the concept of the MinGen, and what the numbers mean. Compared to last year, the MinGen requirement decreased by about 170 MMCF. That result -- that amounts to about a ten percent reduction and a reduction is a good thing. The lower the MinGen requirement is, the lower the gas demand is from our side for electric generation in Southern California.

The reduction is related to two improvements, one is synchronous condenser installation and the other one is the transmission line going into service. Those two attributes, while they're unrelated -- they were independent of the topic that we're talking about today, they do result in benefits in this area and that's why you see those numbers being reduced.

The MinGen number is the minimum gas needed to meet a one in ten electricity demand, meaning that it's not an annual number, it's a higher number than an annual number, it would be considered like a heatwave, a once in a decade type heatwave-type number.

In order to address the minimum generation, we typically have to shift generation outside of this area, or rely on imports. And usually we do a combination of the two. For LADWP side, typically it’s imports other option which is bring the energy in from somewhere else.

The minimum dispatch departs from economic dispatch. And what that means is that we use software to optimize. When you’re looking at a minimum gen number, you’re taking often the most economic units that were part of the solution offline because by definition you’re already running an optimized solution, and that results in increased costs.

It’s achievable by a couple of assumptions. One is that electric transmission lines are at full capacity and operating and available, and that replacement units outside of the SoCalGas area have access to gas. Because oftentimes if you have a regional heatwave, it can be sometimes difficult to get gas. And so you have to have units that are able to get the gas to run in place of the SoCal units.

We do a MinGen determined by power flow studies which is a study of the system and its capabilities to determine that. And then the historically observed one in ten used for the analysis was based on 2017 at 2 point -- just 2 BCF, approximately.

Next slide, please. So back on the MinGen topic and the one in ten. Operating at MinGen means curtailments to electric generation. This is different than Lana's reference on her slide when she said there are no curtailments, I'm assuming she's talking about load curtailments as opposed to electric generation, because we have to reduce electric generation here to save on gas and we have to produce the megawatts somewhere else, either through imports or outside of this area.

Again, it results in costs, we talked about that. It's only feasible when the energy supplies are available obviously competing for resources, it's something that we're looking at when we're trying to bring energy into California during the heatwave.

And it assumes transmission lines are at service, available, and used. This means that, you know, we don't have any forced outages, because forced outages make the system less than 100 percent available. They are a fact of life, they happen intermittently year round, and that reduction in flow could affect the capability to meet this minimum gen requirement.

The table down below is Lana's numbers and looking at it, it parallels her numbers, the item to point out here is that when you look at the one in ten number and the supported demand number for June, you see that you still have a positive number of 229 -- excuse me from the -- for the electrical liability. That 229 is a positive number but it's also assuming 100 percent utilization of the system. And if you had any outages that reduced the efficiency of the system even by ten percent, you could see as a result a challenge in that area. Whereas you have broader flexibility once you get to July 1st and beyond, this typically relates to a constraint because of some gas system maintenance that Lana alerted to -- alluded to earlier.

The next slide.

MS. WONG: So the gas balance cases. We developed three cases and the difference is the timing of the remediation work. So Line 235, the earlier slide had a projected date of June 22nd but I did look at Envoy and it looked like that date was accelerated to, I think it's June 9th. So Line 235 is expected to return to service June 9th. At that time, Line 4000 will be removed from service. And that switchover won't have any impact on pipeline capacity. It will essentially be the same just a different line in service.

And then the base case assumes that Line 4000 returns to service August 9th and you get a little bit more, like a 100 million cubic feet a day or maybe under that more when that line returns to service. The pessimistic case assumes Line 4000 remains out of service and doesn't come back. The optimistic case essentially assumes the base case assumption with increased operating pressure on Line 4000 occurring later in the fall, November 1st. And that would have the biggest benefit by adding an incremental 300 million cubic feet a day into the system.

And so essentially after using those assumptions and producing the gas balance, we see that we can refill storage inventory to that 80, 81 BCF range by November 1st without violating any parameters. And the ending storage inventory is in the 69 to 81 BCF range at the end of December. The one note, though, is that there's a zero percent reserve margin through September, October. And so what that means is that there's not a lot of flexibility in the system for warmer days or unforeseen problems. So if something happens what it would mean is that you would not be able to inject, so if you had above average temperatures for a month, you wouldn't be able to inject as much as you thought you would and it would mean possibly not reaching that level by November 1st.

MR. BAKER: So these action plans have contained mitigation measures in the past and there's 44 of them that have been developed over time. They're included in an attachment in the appendix of the report. Most all of them have been implemented with few exceptions.

And so the focus of this report was to really identify seven new measures for this summer. The first and foremost is to get -- is to get the pipelines fixed. And so it’s to continue having SoCalGas implement six days per week, 12 hours per day work schedules to repair those lines. Also as was mentioned earlier to revise the OFO penalty structure and there’s a PD on the PUC commission agenda May 30th to vote on that.

Revisions to the withdrawal protocol are also offered as a possible mitigation measure, I was talking about earlier. Also, recently SoCalGas made a modification to its OFO formula within some discretion that is has and this could -- this helped reduced low OFOs. And so the technical assessment offers that SoCaGas should work with parties to the settlement that was involved in that to determine if any further refinements could be made to further reduce the potential for low OFOs. Also, as was done in 2018 through the SoCalGas’s second injection plan, look for ways to help customers to use the available pipeline capacity.

And then doing research as well into the gas cost and incentive mechanism to determine if there’s any interaction between how that mechanism is structured and pipeline utilization, because the goal is to maximize pipeline utilization to the extent possible and the purpose is to understand if there’s any connection there and take any appropriate action as a result.

And then, finally, to optimize the timing of discretionary maintenance to maximize injections while minimizing peak summer and winter season maintenance. And this would be done through having SoCalGas provide additional information on its maintenance outlooks and whether those maintenance activities are being pursued pursuant to regulatory requirements to bring more transparency to that. Also we recommend considering whether an action plan may be needed for next winter if the pipelines are still not in service.

MR. BOUILLON: Moving back to the mitigation measures from CALISOs perspective. The communications between SoCalGas and the ISO have been fairly regular for almost -- well, coming up on a decade now. So it’s not new, but we’ve been continually enhancing and improving those aspects of the communication. One of them that we’ve been working on is sharing the information two days ahead of the operating day. This is based on the estimated or forecasted information which helps give the gas company a heads up of potential trends and usage and challenges.

The second one is the ongoing enhancements the day ahead information sharing. The D plus one information sharing is production based, it’s actual numbers that show from our day ahead award what it means to the gas system. And we’ve shared that for quite a while. We’ve improved granularity and also timing of those reports.

Those first two bullets, though, are important because we work with a gas company and determine granularity that matches their systems requirements to help provide as much value as possible. And then beyond that we have ad hoc communications that are proactive as we reach like heatwaves or challenges in the system, we'll talk nightly or early morning typically ahead of the day with the gas company and then we also talk regularly at multiple levels of the organization addressing issues or challenges that we see in advance of them actually happening.

We do continue to maintain tools that help manage gas use. The burn constraint is one that we have the ability to actually match our generation to the best extent possible to limitations on the gas system. That is a reliability tool that we use. And then improving the gas index price, that's something that's relatively recent from CALISO to help make generators whole for recognizing their actual cost for procuring the gas over timeframes where you don't have true visibility of the pricing.

And then, let's see, dispatching resources that have alternative gas supply. This is the way for us to have the ability to shift the generation which I referred to in a previous slide. And then obviously to use the flex alerts to help reduce overall demand which greatly helps with our flexibility.

Looking forward and talking about projects coming up, there are two projects that are scheduled to improve the transmission facilities and strengthen Southern California energy reliability. Those two projects include a study for our compensator installation which is expected at the end of this year so it won't help us this summer but it will help us next summer. And then you've heard lots of discussion on the Mesa Loop-In. That is not slated for a couple years but again, that's another improvement. Both of these items will continue to help us be able to push down the MinGen requirements in this area basically taking the -- helping the gas system to become less stressed and giving us more options electrically to shift the generation around.

MR. BARRY: Good afternoon. My name's Glen Barry, I'm the manager of Energy Control Operations for the Los Angeles Department of Water and Power. I'll be presenting the next two slides.

First one here is the completed mitigation measures that L.A. has taken and their estimated impacts. These are all measures that have been in place for at least a year or more and we continue to use them.

First one, increased electric and gas operational coordination. This improved coordination between utilities has increased L.A.'s situational awareness particular during critical high heat days. We've updated physical gas hedging practice. This provides additional operational flexibility for LADWP in the event of gas curtailments or curtailment watch periods.

We have updated our economic dispatch practice on those curtailment or curtailment watch days. This provides additional operational flexibility for us on noneconomic energy purchases reducing reliance on local gas by approximately 1.7 BCF total gas burn.

We've also updated our block energy and capacity sales practice which provides additional operational flexibility for L.A. in the event of gas curtailments or curtailment watch periods. And we continue to maintain dual fuel capability at three out of our four in basin plants. That's approximately 1500 megawatts of alternative fuel capability only to be used as a last resort to maintain electric reliability in emergency situations.

Next slide. And the next slide here will be facilities we have planned in the near future to lower gas burn, I think Jason Rondou went over some of the longer term plans that there certainly will be more of. But reduction of our minimum gen requirement, we have four in basin 230 kV lines that are scheduled to be reconductored and have a -- have their ratings increase which will lower that minimum burn gen.

The first two lines are in the process now of being reconductored, expect to have those completed in the winter of 2019, 2020. The second two lines will start immediately after that and those are expected to be completed in the spring of 2021.

Additional transmission projects will be determined in the future. And as I think Brad mentioned earlier, transmission projects that will be critical to reducing in basin gas generation and meeting the SB 100 clean energy goals, and we continue to look for ways to reduce our minimum gen requirements.

One new renewable generation facility that's coming on just before the summer, has an additional 90 megawatts of utility solar that will be added June 2019.

MS. WONG: So our outlook for this summer really comes down to the outages, balancing keeping our supply demand in balance, and weather, even with mitigation measures in place. So our risk to electric generation is similar to last summer except for possibly for the month of June as I mentioned. If we do see a peak day occur in the month of June, it may require withdrawals from Aliso Canyon. Likewise, if there's reduced transmission utilization on the electric or gas system also may require withdrawals from Aliso Canyon. What we'd like to see is the system fully utilized before curtailing generators and you want your demand less than that so-called supported demand or capacity.

And we talked about mitigation measures and ways to mitigate reliability and price risk. Well, restoring the pipelines, getting the pipelines back in service is the number one thing and is essential to providing certainty to mitigating price and reliability risk.

So next steps, we'll continue monitoring things, we'll look at the mitigation measures that have been proposed, and determine what could move forward. And again, we should consider whether an action plan for winter is needed if the pipelines are still out of service. And comments are due June 6th to the Energy Commission. Thank you.

VICE CHAIR SCOTT: Great. Thank you very much. This was very robust information and a well written draft assessment that you all put together that came out just a few days ago.

So we're about ten minutes behind time because of the WebEx, so I'm going to see if we have questions here from the dais for folks.

Yeah, David go ahead.

CHAIR HOCHSCHILD: Yeah, just really quickly. You mentioned going to a 6-day workweek, 12-hour days. What would be sufficient to drive, you know, a decision to work beyond that, longer shifts, or 7-days, I mean.

MR. BAKER: Yeah, that's something that we looked at at the PUC. We have Matt Epuna from Safety and Enforcement Division coming up next, perhaps he could speak to that in more depth. But we did investigate that thoroughly with SoCalGas and in essence we found that the safety trade-offs of going to, you know, a seven-day week or, you know, a 24-hour day for the relatively minimal gain was in our determination not worth the trade-off.

CHAIR HOCHSCHILD: Okay.

VICE CHAIR SCOTT: Other questions?

Yes, Laki, please and then Cliff.

MR. TISOPULOS: A very robust presentation, so I'm still trying to digest and sift through the [indiscernible] numbers that you presented. The one in ten scenario, does it factor in the cold winter that we experienced this year?

MS. WONG: So for this assessment, it's focused on the summer period. So we're looking at a one in ten summer peak day demand where you have EG at its peak. So it flips between summer and winter, so this for -- demand forecast for summer that is used is different than what you would look at in the winter on a one and ten, but --

MR. TISOPULOS: Got it. And I'm assuming in that scenario, you are -- there's an assumption that certain fraction of the capacity pipeline capacity is lost due to either maintenance or ruptures, I suppose, you know, the ruptures are the main drivers, versus the temperature swings that we are experiencing. Which one's the main driver, the main contributor to the short fall or the surplus or is there such a thing?

MS. WONG: So in the June timeframe that I had referenced, probably the main driver there is the additional maintenance on Line 230 -- 2001 because it's a lose of 350 million cubic feet a day. So the risk is, if that peak day occurs in June, that you still have outages and maintenance going on on the gas system during this timeframe.

MR. TISOPULOS: Thank you.

VICE CHAIR SCOTT: Cliff and then Mark -- oh, I'm sorry.

COMMISSIONER RANDOLPH: I just had a question about Wheeler Ridge. You mentioned that there was maintenance last summer and maintenance this summer.

MS. WONG: Right, right. And they're short events. So I don't remember the specific maintenance events. So SoCalGas, this is part of an effort to provide more information on its outages. It developed what they call a maintenance outlook, so there's not as much certainty to those dates that are published there, as maintenance on what they call their maintenance schedules. So I just looked at the maintenance outlook and I noticed oh, Wheeler Ridge because we've seen this over last summer and then November, December that these incremental maintenance events on top of these outages already in place can contribute to the price spikes we see.

COMMISSIONER RANDOLPH: Okay. So we can ask the company when they come up to see if we can get some more information on that too. Yeah.

MS. WONG: Right.

COMMISSIONER RECHTSCHAFFEN: Could you go over again what the reason is for the reduced capacity on the non-Aliso storage fields and will those persist to the winter too?

MS. WONG: So the -- as Simon mentioned about twice as much inventory was used this past winter as the prior two winters. It was somewhere around 42 BCF used. And in part, the withdrawal protocol in place can contribute to what's left in the remaining fields. So Aliso Canyon is a resource of last resort so when you're initially withdrawing from storage to meet our demand, you're pulling from the other storage fields. So the -- it will draw down those first and leave more gas in Aliso Canyon.

But in addition, to that Simon also discussed the shut-in's, Honor Rancho was shut-in for three weeks in April and so during that time period, when SoCalGas was injecting gas in to storage, all of that gas went in to Aliso Canyon during that time period because Honor Rancho was shut-in for the semi-annual shut-in for verification and testing under those new DOGGR rules.

So its just currently they're lower, that if you look at okay, where is the gas stored today? It's mostly at Aliso Canyon. So the current numbers that we have about 29 BCF at Aliso Canyon and in the non-Aliso storage fields collectively. It's about 23 BCF. So right now we have more gas at Aliso, which is why if there is a peak day in June, the withdrawal capability out of Aliso is far greater than the other fields.

COMMISSIONER RECHTSCHAFFEN: All right. And that answers the other question I was going to ask you. Which is what is the capability is at Aliso right now, given that they were injections in April? I guess, I'll ask the gas company what they're plan is for the remaining six months. I take it that the peak summer season starts pretty soon. So typically injections don't happen during the summer but I don't know if that's universally true or has to be true.

MS. WONG: Well, no, the injection season runs from -- in the gas world, April 1st to October 31st that's considered your gas injection season but it will occur mostly in the shoulder season when demand is lower but, you know, then you have these additional DOGGR rules that are going to make refilling inventory more challenging because you have less opportunity for injection.

And last year, if we look at when did they fill inventory? Late summer, the weather at the end of August in to September just turned more mild and they were able to inject in that time period. So it really does come down to the weather. So it could happen during -- what you would think is a peak summer month August and they were able to inject.

COMMISSIONER RANDOLPH: I have a quick question. Oh, sorry Mark.

VICE CHAIR SCOTT: I think Mark then you if that's okay.

MR. ROTHLEDER: Yeah. Brad, I think this year and going forward there's a new dyn -- operational dynamic that developing and that's the public safety power shutoffs to the extent they effect transmission. How could that interplay potentially with the MinGen and getting alternative supply?

MR. BOUILLON: That's new, yeah, that's new going forward. That would be treated just like an outage so it would actually reduce transmission flexibility potentially impacting the MinGen requirement, because it would restrict our ability, depending on where the lines are taken out of service. It would restrict our ability to flow energy around in lieu of using generation in the L.A. Basin.

COMMISSIONER RANDOLPH: On the demand response programs, I know the company is going to do -- talk a little about that in their presentation in the winter look back. But do we have a sense of the numbers sort of, you know, of reduction and demand from that program?

MR. BAKER: Yeah. We're going to be getting an evaluation report on the therms savings from the demand response, that's coming in June. So our plan is to have the winter lookback report was published as a draft report because there are a few elements that are going to be added before it gets finalized in third quarter.

One of them is the therm savings for demand response and then also, there's an analysis that LADWP did and that CAISO will do as well on what were the incremental cost or price impacts to the electric system.

COMMISSIONER RANDOLPH: Thank you.

VICE CHAIR SCOTT: Yes. Go ahead.

MR. TISOPULOS: One quick question. --

VICE CHAIR SCOTT: I think Laki and then Martha.

MR. TISOPULOS: So the one in ten scenarios, very conservative scenarios, and a reasonable exercise to go through to test the capabilities of the system. I was wondering in addition to the high temperatures that we have experienced, let's say in this region, does it also factor in any loss in the pipeline capacity in the event other parts of the country are also experiencing heatwaves and they are pulling the gas in one direction and the gas cannot come in this direction. Is that also a variable that is being factored in, is that in those one in ten scenarios?

MS. WONG: So the initial assessment is looking at full utilization of the gas system and so we do raise the issue that if there are additional supply constraints due to, you know, the issue you raised or further outages on the system then these numbers would actually be lower. Like if you see a surplus in one time period, well, that surplus would essentially get eaten away by these events.

VICE CHAIR SCOTT: We'll do Martha and then a last question from Commissioner McAllister if he has one from the phone, otherwise we'll -- after Martha's question we'll turn to the next panel. Please, go ahead.

MS. ACEVES: Thank you. I just was looking about -- thinking about last year or maybe it was January in the last workshop where we talked about different mitigation measures. And a couple that were -- or one that wasn't mentioned today, one that was mentioned earlier -- one was having the gas company for core balance to the actuals, and I didn't see that on this particular listing.

And then the other is related to kind of your question around may be this is a new normal and that our electric system needs to adjust in a way that hedges more broadly to these gas spikes.

And the proposal that Southern California Edison made to have an electric generator tariff where the gas -- the gas -- a gas tariff essentially.

And I wonder why that's not listed here or if you guys discussed that?

MR. BOUILLON: We're going to tag team on your questions?

MS. ACEVES: Okay.

MR. BOUILLON: The question on the core balancing, the gas company's up later today so they can talk further to it, but in general, in the winter time core consumes a lot of the gas pipe so it's very important that's probably where the balancing piece came from the previous one.

In the summer time you have much less percentage of core in the pipe so it becomes less critical in the balancing as opposed to the electric generation consumption of natural gas.

MS. ACEVES: Is anyone going to answer the second part?

MS. WONG: Okay. Can you repeat what the second part was?

MS. ACEVES: Okay. Well, if Edison is here, they may be able to elaborate on it better, but the proposal that I recall is that because the merchant generators -- electricity generators are looking at gas as an input that just passes through and compounded with the OFO up to the higher electricity prices, that they have no incentive to really kind of forward or hedge as LADWP said on their gas. And, I think the proposal essential from SCE was to have an established allocation and tariff on the gas supply for these merchant generators.

MR. BAKER: Yeah, that's right. The proposal was to have basically kind of a gas procurement tariff for electric generation. And that was from the January workshop, I think it was framed as kind of more of a, you know, medium to long-term solution and likely one that would need to be taken up in a rule making activity of some kind at the Public Utility Commission.

So for the moment we've been focused on the short-term issues but then when it's commission turns its attention to the longer-term there're are opportunities to be able to bring that issue potential in to a future rule making.

VICE CHAIR SCOTT: And let's check on the WebEx, if there is a last question from Andrew.

COMMISSIONER MCALLISTER: Yeah. Thanks, it's been a really, really interesting discussion, thanks for all the hard work. I think the tag teaming worked well.

I do just want to ask one question about the non-Aliso fields. And it certainly this is -- probably more of a question for SoCal when they come up. But is your collective feeling that we're doing that -- everything we can to get the, you know, squeeze the most juice out of those fields? You know, keep them operating, keep them injectable, withdrawable, is there anything else we could be doing there to help them be all they can be?

MS. WONG: So as -- this is probably best addressed with SoCalGas but as I understand it all of the fields are undergoing this storage integrity management plan and that includes Honor Rancho. And I mentioned that the withdrawal curves and the maximum withdrawal capability may be a little different under -- after these fields undergo that conversion to tubing only. That's one of the requirements of the new rules in place.

And so I think, you know, again the gas company's probably the best one to answer that but as far as usage goes, you know, these fields are all being used.

VICE CHAIR SCOTT: Okay. I know I said that was going to be the last question, but I had one also. I just, Simon in your presentation, at the very beginning you mention that there was a set of mitigation measures and it was kind of a mixed bag in terms of how well they worked. Was it a mixed bag kind of overall, like sometimes a particular measure worked really well, and sometimes it didn't? Or is it -- was it a set of measures that always did work well?

MR. BAKER: No. What I was referring to was specifically the electric generation curtailment measures. And based on our assessment that given that kind of cost of that from the, sort of efficiency stand point on the electric system, didn't seem to be gaining that much in terms of actual gas savings.

VICE CHAIR SCOTT: Thank you. With that, thank you very much for all of the fantastic information that you have provided to us today. We very much appreciate it. We will transition now to Panel Four which Other Safety and System Operation Perspectives. We're a bit behind time, so I'm hoping we can kind of go about 2:23ish to 3:00 with this panel.

As they make their way up, I will remind folks that if you'd like to make a public comment, please fill out one of these blues and get it to either our public advisor or to Heather and she'll get them to me and that's how I know you'd like to make a public comment.

So I'll let them get set up and we will go from about -- this a 2:23 here to about 3:00 for this and so please leave us a little time to ask you questions as well. And welcome, we're glad to have you.

MR. EPUNA: Good afternoon. My name is Matthewson Epuna. My discussion today and presentation will be based on conversation the CPUC had with our sister agency Energy Commission and I sort of tailored my presentation to address those questions that were raised. So you may see kind of shifting from one topic to another without really any major reason for that. It's basically to address the questions that were raised by CEC.

First of all, I would like to speak about -- speak truthfully about the authorities that the commission has and how the origins of those authorities to regulate or have over -- safety oversight over the investor owned utilities in California.

The commission under 49C -- 49 USC code 6015 acquired the authority to regulate all investor owned utilities in California through a certification and an agreement with Office of Pipeline Safety and Hazardous Material Administration.

That authority also included what we recently received from PHMSA. Authority to regulate -- or rather see -- have safety oversight over municipalities which is the USC -- 49 USC 60106 agreement, gives us that authority to regulate municipalities. By that I simple mean that we have safety oversight but nothing else basically the commission will perform the safety oversight, any findings will be written up and sent to the feds and the fed will do the enforcement. So we have no enforcement authority over the municipalities but just to conduct the safety inspections.

And so in light of this the commission referenced these federal code through our general order 112-F, to address all the pertinent parts of the federal regulations which are parts 190, 191, 192, 193 and 199 which talks about drug and alcohol misuse prevention program.

So most of you already know that the federal code prescribes minimum safety requirements. In order for minimum safety requirements to address design construction, testing and operation, and maintenance of gathering lines, transmission storage and distribution, and distribution pipeline system. So this many more requirements simply means that each state program or partner can establish a more stringent rule than the minimum federal standard. So as a result the commission has additional standards that we have prescribed for the operators to comply with.

In addition to these minimal federal standards, and the commission's requirement, the operators are required to do several things, before I go further, let me just talk about some of the major operators that the commission has jurisdiction. These are the major gas operators that the commission regulates or has safety oversight.

One of the questions we had was whether the operators should have replaced Line 235 pipeline when it ruptured or continued to do replacement repair of segments as they find the leaks. And I would like to start off by giving -- or providing some of the facts that we have.

On October 1st 2017, Line 235 ruptured at location west of the Newberry Springs. After that rupture, the commission management and engineers met with the operator to discuss the operators action meaning the -- when the rupture happened the operator planned several things, one they commenced or commissioned a root caused analysis which we felt was an essential part of determining the probable cause of that rupture. So their root cause analysis was commissioned, when the result of that root cause analysis came out we requested a copy of it, received it, reviewed it, and then requested a meeting with the operator to discuss some of the findings.

And through that, we discussed their approach going forward and that was when the operator informed us that they are looking at various ways of addressing or -- rather enhancing the current system meaning to -- when they received the integrity results, they want to have a better feel and understanding of how to approach it. Obviously, the previous method was not able to detect this particular problem prior to the rupture.

Okay. I was just reminded I don't have to much time so I'm just going to go quickly with these.

So the operator in order to address this explained to SED of the commission and safety and enforcement division that they leveraged analytics from their vendor, one of the vendors they commission to do study for them, to help them capture some of the essentials of what they need to do to determine whether they need to replace the entire segment or some of the segments and that analysis indicated -- or identified some of the locations that they needed to replace.

So I guess the point here is that should you replace the entire segment, or replace some segments, or repair as you find the leaks until having some actual data to help you make that decision and the op -- the contractor, the operator hired looked at various scenarios. One of them was the likely hood of a failure based -- caused by rupture versus if it just failed through leaks only, a small leak.

So the op -- the vendor identified six locations that needed to be repaired and they believe that those six locations will cure the integrity issue as well as rupture.

The operator completed that -- or was almost -- almost at the end of the completion, when they discovered some leaks.

And one of the processes that they have to go through to bring a line back in to service after it has gone through a major repair, is to conduct leak survey until that line shows no leak before it can be brought back to service. And during that process, they discovered a leak and those leaks have to be repaired.

So these are the -- the slide is showing the six locations that were identified for replacement that the operator replaced.

So on March 23rd the operator discovered two leaks during its process to bring the line back in to service and this happened like two days prior to the return to service date. So the operator commenced repair action. As they were working on that, on April 8th they discovered two additional leaks. And they completed those -- those have been completed.

And then -- okay. Then on April 19th during a gas leak survey the operator detected leak five on the pipeline and as they detected leak five and they decided that in order to help expedite the process, they were going to divide the pipeline in to three segments; the middle and the right and the left section, they will pressure -- they're working on the middle section, so they will pressurize the left side and the right side, bring it up to the pressure that it's supposed to operate. Because the leaks tend to -- seem to have concentrated, this is a map showing where the leaks are, leak one, leak two, three and four appear to concentrate in the middle section. So rather than wait till after they complete that and ramp up pressure on all the lines, they decided to ramp up pressure on the left-side and the right-side while they work on the middle section.

During that period, both left and right sides -- they surveyed those and did not find any leak, however, as time went on a leak appeared on the right-side which is leak five and then another leak appeared on the right-side. So on the total they have seven leaks and they've -- and they're working on those and the return to service date is projected to be sometime June 8th.

So commission throughout this process has had an oversight on this remediation activities. And these are some of the issues that we discuss with some of the data request that we sent to the operator to help us understand what they are doing and I must indicate that the commission, some of the commission's oversight it's weekly inspection, in other words we have our engineers at the site weekly and some time some of those inspections are unannounced.

So one of the questions, data requests we sent was what matrix and project management did SoCal use in measuring its progress against the time line of it's Line 235 remediation schedule?

And the second question provide basis for your current in service estimate? What are the conditions, factors that may contribute to remediation schedule delays?

They -- most important one that we brought up to them as well as actually raised by two commissioners that are sitting here, Commissioner Guzman-Aceves, and Commissioner Randolph, was for them to conduct an assessment -- risk assessment and analysis of the impact on the return to service date if work schedule is increased to 7/12 or 7/24 meaning 7 hours or rather 12 hours every 7 days a week or 24 hours 7 days.

So the operator provided response to SED on these questions and at the end determined that 12 hours 7 days a week was the appropriate, that was appropriate way to go and prevent accident or injury.

And these are other CPUC oversight work that we work that we've done. The commission has been exercising oversight for this process and then had multiple times we meet with the operator do discuss various issues, both the root cause analysis, and the structural integrity analysis.

And then the operator adopted that 12 hours, SoCalGas completed the replacement sections, that part it's done, except the three leaks that are remaining.

CPUC engineers maintain and continue weekly field safety assurance activities on the repair -- both on the replacement work and the repair work.

In addition to that, we have a standing weekly, CPUC has a standing weekly reliability meeting to help us understand and stay up to date on this remediation activity.

Commissioners again, Commissioner Guzman-Aceves, and Randolph have been highly concerned about the reliability impact of Line 235 outage and has requested and received frequent updates on Line 235 remediation.

Our commissioners question the amount of resources and work hours the operator has devoted to this remediation.

CPUC engineers and management have constantly discussed the steps and processes expedite the remediation activities with SoCalGas. And we current -- CPUC currently has a weekly standing conference call with SoCalGas to also understand the real -- reliability updates and other issues that may create reliability issues.

The question about repair -- why is the repairs taking so long? In my opinion, I think SoCalGas is best suited to this question. However, I would talk in general about repairing a pipeline defect that will depend on vary -- on varying factors such as type of the defect and geographical location of that defect, cause and size of that defect, and weather condition, and environmental issues, and availability qualified work force.

The other question that I did receive was, why are other federal mandated requirements or maintenance requirements that may impact reliability? And there are some I -- this is just a few of them, one thing to keep in mind is that the federal regulation prescribes minimum safety standard.

Okay. That minimum safety standard, the operator, it's required to exceed that meaning have a best practice that it exceeds the minimum safety requirement. So one of the things the operator is required to do is provide a written procedure that will guide how they operate and maintain the system. And that written procedure the operator can specify some of the activities that they deem best practice which will exceed the minimum -- the prescribed regulatory standard. And we will hold them to that standard that they've prescribed, meaning if they said that's what they will do, we hold them to making sure that they are in compliance with that.

VICE CHAIR SCOTT: So I just want to do a quick time check. We're about 20 minutes in to a 40 minute and we got another presentation, so if you could may be gives us about two more minutes and then we'll switch to our other presentation and I know my fellow folks on the dais will probably have some questions as well.

MR. EPUNA: Okay.

VICE CHAIR SCOTT: Thank you.

MR. EPUNA: I will wrap it up. Okay. Amongst this there are some discretionary maintenance activities the operators are required to do. Before I say that one of the mandatory maintenance requirement that they must perform is the commissions pipeline safety enhancement rule that says that every operator that has a transmission pipeline -- or intrastate pipeline -- transmission pipeline that does not have traceable or verifiable and complete record must either test or replace that transmission line and then he has to perform other functions.

One of the issues we were asked to address was the permitting issues that one I would just specifically say that pipelines run through various areas, one it's environmentally sensitive lands, federal lands, and endangered species habitat and these are regulated by certain federal and state agencies. And in order to perform work in it you must obtain proper permits to do so. Thank you.

VICE CHAIR SCOTT: Thank you. Next is Rod.

MR. WALKER: All right. That's the end, we don't want the end yet, we want the, yeah. Well, good afternoon. My name is Rod Walker. I'm the CEO and President of Rod Walker and Associates Management Consultancy in a technical advisory firm based near Atlanta Georgia. You probably couldn't tell that I'm from the south by the way I talk, but I will try to speed up a little bit I know we are constrained on time.

I'm -- appreciate the opportunity today to speak to you on the very important subject of reliability. My presentation, the one I was asked to put together is to look at reliability not only in Southern California but across the nation. I've been very blessed to be apart of a lot of different exercises in activities throughout the country in my few years in the natural gas business and I have a perspective on that as well as some best practices.

And then some other tidbits from my other work with jurisdiction, other state commissions throughout the country to come up with a list of potential options or ideas to consider and I'll say this now and I want to say it at the end when we get to the options. The options are meant to be a list of things to think about and questions they're not questioning.

I have done 50 some due diligent assessments of utilities across the country in my experience. And so my natural view is to try and figure out where the obvious questions that need to be raised. So I want to say that now, because I believe everyone in this room, you know, this is a family event, and we're all trying our best to be --provide reliable, safe, economical natural gas service to Californians.

Real quick on my background, I am -- I've had basically 34 years and I know I look younger than that, in the natural gas industry, 17 of that in industry and 17 in consulting. I worked in a variety of engineering operations and management roles at Atlanta Gas Light Company, some of you may have heard of Atlanta Gas Light Company a large natural gas company based in Atlanta which is now part of Southern Company Gas. I also worked for two small municipal systems. In consulting, I mentioned due diligence, I've done a significant amount of due diligence and risk assessments as part of working for other large indust -- consulting firms, Black & Veatch, R.W. Beck that come to mind before starting my own business a couple years ago.

I've been involved in California for a better part of ten years. I was part of the initial Aliso Canyon independent review team working with the Los Alamos labs to review the assessments that were presented today for technical work in hydraulic modeling that SoCalGas had done.

So I'm familiar with the SoCal system and I think energy situation in California from that work as well as two other projects with storage, with the report right on the CCST, storage report that came out last year.

And I'm now currently and have been involved with the California Energy Commission supporting the hydraulic modeling project which a is very exciting project. It's the first in the country where a planning agency like the CEC is actually working collaboratively with the two largest utilities in the state to model the natural gas backbone.

And then lastly, I'm an expert witness for the State of Rhode Island, have been involved in not only their reliability what they call their ISR, rate for reliability annual analysis but also, the -- if -- we'll talk about it in a little bit, if you read the news, there was an outage of about 7 to 10,000 customers in Rhode Island and so I'm on the team that's leading the investigation of that outage as well as another event due to aging infrastructure.

My background is varied. I'm an engineer, civil engineer from Clemson University. I've done a lot of system design planning, modeling, replacements, but also have a significant amount of management responsibility so I understand both sides of the business.

So a little bit of an overview on reliability. Some of this you will already know and have been touch on by other speakers but reliability is not mandated or regulated nor tracked to the natural gas industry unlike the electric industry to some degree -- or electric brethren and sisteren are very much held accountable for liability matrix, safety sadie, all those type things. Where the natural gas industry has largely never had that kind of matrix to live up to.

So in essence it's left up to each gas company to plan and implement their own improvements to ensure reliable -- liability natural gas system, or the system to the customers to make sure that basically the gas stays in the pipe.

The trends in the country, our country show a wide disparity of reliability in this country. And when I say that, I mean, in terms of primarily aging leak prone infrastructure which is typically the cause of a lot of our reliability issues.

So obviously we're talking about SoCalGas and their issues with their critical infrastructure being out of service for a long period of time. I alluded to the issues in Rhode Island with National Grid. They had significant customer outages that were caused by aging leak prone pipes and other issues in that led to the outage of 7 to 10,000 customer, which is very unusual.

And then on the other hand you have Enbridge that had a major pipeline back in service within several weeks and other projects. Colonial had a -- has had several gas line -- gasoline breaks in Alabama, they were put back together within a week or two and obviously we've -- you heard there were OFO or Operational Flow Orders, but we've seen a lot more of those in peak times and some of it is because of reliability issues not necessarily because of weather which is typical in previous times.

So I'm going to skip through this, my friend Matt has gone through some of this but I want to touch on a couple things that I think are very germane to our discussion. Integrity management is set of regulations that came out dur -- after the San Bruno incident, planning remediation work the gas utilities have been doing or should have been doing since the early 2000s.

And so that means initial baseline of the transmission system for every utility should have been done right after those regs came in to place if they hadn't been done already. And they have to be reassessed every seven years.

We've talked about pigging and that sort of thing and then what's, you know, defined the issues with the pipeline. Basically, the operator has to find the threats on their pipeline and do the appropriate investigation of what they think is cause in potential leaks. And in the case of intelligent pigging those tools find a lot of the anomalies in the things that cause the leaks.

Planning and modeling just really quick, hydraulic modeling is used to check the system's ability to provide enough gas during those types of events when you're having to take pipes in and out of service.

But also, the trend in the gas industry is to go more to an asset management approach. So that you're looking more the end of life not just a matter if a pipe's leaking or not. And so that is a view specifically because if you're doing a replacing program you -- sometimes at some point may never catchup from an age perspective. If you're looking at your worst offenders, you may not get to the ones that -- behind -- or behind the worst offenders and so you have this rolling need to keep replacing pipe. So there's been more of a view of taking a holistic approach to get rid of larger sections of pipe that were put in at the same time.

California and it's specifically is different than the rest of the country in terms of its gas system. The pipeline companies own pipelines and storage in most states in this country, in other words you have a Williams Transco or you have a Transwestern or an Enbridge that owns the transmission and the storage facilities and the gas distribution company, like Atlanta Gas Light, where I use to work, owns the gas distribution system. In this state the gas companies own all of it so they're responsible for pipeline, transmission, storage, and distribution which is a lot on one plate.

I will not walk through the issues because they've been talked about several times but there are a number of obvious issues with infrastructure here in California.

I think the general gist I want to convey is they're old pipelines that are -- they have leaking, they're leaking, they're aging and reaching what seems to be end of their useful life and it's not just one or a couple but it's noticeable that there are fairly strong number 235, 400 -- 4000, 3000, 2000, 2001 and so on, which are critical infrastructure in the state.

In general there's not as -- not redundancy you would see in a transmission pipeline company's portfolio where they have two redundant pipelines of same volume where they can -- if one is down, they can take it out of service and continue and you'd never know that you're impacted because they have redundancy.

You have some instances of that with 235 and 4000 here but largely you only have one pipe in most cases or in the case of 235 and 4000 they both have issues. So it's hard for one to be the backbone when the other one is down. So that is -- these are points to bring to mind that are different here.

Okay. So these are the points to consider, these are questions again, these are ideas. This is me a consultant and an industry person who's been involved in a number of projects and has actually been here as just a -- understand what's going on. And frankly a lot of this is from public data, so I always say, I may not have the story completely correct because I'm going from the data that I have.

But just, you know, what comes to mind why these issues with the pipelines, they seem to have just popped up in the last three to five years, and may be I'm misunderstanding that, I have to Aliso Canyon leak but specifically with integrity management in the requirements that I just talked about that started in the 2000's most operators should know the oper -- the condition of their pipes and have a plan to repair and replace. And so in general just curious what the plan has been all along for these pipelines that are now causing issues.

And on inspection tools, were not used in 2010 and again I may have that wrong, but they've been available for a number of years and just curious to when they first started their baseline assessments and initial evaluations of this critical infrastructure what they found in terms of their results.

What’s been stated already, a couple times taking too long to bring back in to service, national average is weeks and months not years for similar repair issues. Again, obviously lots of issues with any pipeline repair and replacement so there probably are other things that are different and germane but I think the general message from not only myself but others, is that we need to get the pipelines back in to service now.

Find the repairs and replacements that are the most critical that have to be done to get the pipes back in to service at the highest pressure and capacity possible. If it’s going to be too much of a danger to do an uprating and have to keep doing leak surveys and then find other leaks and issues, separate the pipe to get to the highest pressure and volume that could be used, I would suggest, you know, trying to find a happy medium so that you can get the key pipelines back in to service now.

Validation digs, had this discussion previously in discussions before here that validation digs for everybody, when you do an intelligent pig run, you get basically it’s like having an ultrasound, you have a report that has pictures of the pipeline and someone has to read that and tell you what the problems are. Those reports take 6 months, 3 months, 2 to 3 months to get the final report back.

So what a lot of operators are starting to try to do so they don't avoid getting in to the winter season and having to take pipelines out of service is get at least some since of the problems with the pipeline from the informal report that the pipeline pigging company gives you in 30 days.

So one suggestion is especially with 235, 4000 conundrum is try and do something with 4000 as soon as you can so that you're not going to get in to the winter season and continue, as I think Lana mentioned go to the winter season or close to it with that pipeline being out of service.

Permitting conditions this is a general statement if you can accept them more quickly and especially on the environmental side essentially decide that you're going to mitigate and move forward that's a one way to speed up the project.

And lastly, to some degree however we can hold the gas company accountable for a definite back in service date, I mean that carefully and politely and as nice as possible that -- I know everybody's trying but what is the real date that we can expect to get the pipeline back in service?

I think that’s a reasonable thing to ask and I think the subject, the discussions are already started on weekly reports and weekly meetings to understand a little better more intuitively what’s going on in terms of a weekly schedule just to see what can be done to help them mitigate the issues. It could be that, like I said, this is a family event, there’s something in this realm that someone can do to help mitigate whatever the issue is.

One -- from other jurisdictions and when I worked in Atlanta Gas Light, when we had issues with getting pipelines back in service quickly our public service commission took rate pipeline -- pipelines out of the right base until we were active, it was more of a polite message but also particle because if it was out of service in their mind it was not fair to have it in the rate base. That’s another mediation option that’s being -- basically being done in other parts of the country.

Inject LNG from Coastal Azul, I think this one is not as much of -- really is not viable from what I have now understood, the general idea was if you inject LNG in to help supply the San Diego area, then the gas that is coming from some of the major pipelines to serve San Diego you could bypass and move straight to the Basin. But 2000 -- in 2001 those pipelines have issues and so there’s really not a benefit from doing that so I think this one is probably not germane.

Reliability focus should be on the pipelines, not the Aliso Canyon storage field, I think in some ways, it is masked infrastructure issues in the past because you've not really had to -- you had to rely -- you had the storage field there to, you know, to inject and help when there are issues and now you may or may not have that storage field. So it's time to really think about what needs to be done with the backbone in general. It's not just the couple lines I mentioned but there are others that potential have problems.

And then just thinking out loud, does the state have the staff to adequately ensure SoCalGas can meet obligations to provide reliable, safe and economical natural gas service in California. I mean, in general just being involved with other jurisdictions when things happen they have to step back and evaluate because it is a lot of work to keep up and when you have the two -- some of two largest events in the natural gas events with the San Bruno and Aliso Canyon, it just takes a significant amount of different resources and frankly a lot of technology resources as you may not have had previously. So just a thought to consider, do you have the correct staff, and do you, you know, do you need to augment that?

Jurisdiction I worked with in Rhode Island after the Merrimac Valley incident in Massachusetts where there was over pressurization of a pipe that killed one person and was very tragic, kind of said, oh, we probably need to pay attention, they have, in Rhode Island the largest amount of cast iron in the country and so they've hired staff, they brought in several experts like myself and others just to help backfill. And so I'm not saying there's a right or wrong answer, just saying it may be good to take a look.

And then the last one I want to leave with you is something that other states are doing. And this is meant to be a help not to be a -- when you said audit, it sounds negative, but it's essentially meant to be a tool that will help all stakeholders in the room to understand what's going on and specifically to help identify what's working and what's -- what areas may need improvement in the gas company themselves.

This is a practice that's done in Pennsylvania, they've done it for a number of years and I've actually been a part of a team that's helped the utility to respond to that and in frankly a lot of it stuff they are already doing but it does help to gel the plan moving forward and it ties together what -- the work that say Matt is doing and others are doing on different parts of what is called regulatory and some of a broader base holistic view of the utility itself. And frankly just to help be transparent so that we can all understand what are you dealing with and what can we do to help. So I did this as quick as I could, it's 3:00 so with that, that's my presentation.

VICE CHAIR SCOTT: All right. Thank you very much. Let's see if we have questions here on the dais. Yes, please.

CHAIR HOCHSCHILD: I just wondered if you could comment on the pace of the repairs that, you know, with 235 and the others that we've been talking about here. I mean, it does seem disappointingly slow and I'm just curious, you've seen in other states, is this typical? Does this seem -- just -- how do we stack up to other states on this?

MR. WALKER: Well, any time you say two years, it does sound like a long time and I think my general view from the limited information I have is that I think you have two things going on, you're trying -- and I'm -- the gas company folks can correct me if I'm wrong but you're trying to repair and replace the initially what happened and then you've had to reduce pressure in other parts -- in the pipeline as well, so you're having to not only fix the problem but then you have to go through an uprating procedure where you have to do leak surveys after every time you raise the pressure.

And so when you do that typically, especially in old pipe, you're going to find things and so it sounds like that's been a little bit of a cycle. And so I think that's my -- one of my recommendation was to try to find the happy medium of getting it to a place you can just say it's good for now. I think in general 235 if you saw Matt's drawing with the dots on it, it may be a candidate for some sort of replacement like Line 3000 or parts of it. So do you want to have that discussion, or you've had some discussions already but do you want to, at some point go, you know, what is the end game and how to we make sure this lasts ten years.

But the long answer to say, it seems long.

VICE CHAIR SCOTT: Other questions? Go ahead, Martha, yes, please.

MS. ACEVES: Sure. Yeah. And I guess what would be good to compare may be apples to apples as in scenarios where other rebuilds have so many environmental constraints like the protection of the tortoise.

MR. WALKER: Yes. [indiscernible] tortoise. Yes.

MS. ACEVES: But did I understand you correctly right now, that you're suggesting to allow some minimal leakage and while operating? No. I'm sorry.

MR. WALKER: No, no, no. Leaks are not good. That was more of what pressure do you want to run the pipeline at because the higher the pressure it's going to expand the pipe and there's going to be leaks if there --

MS. ACEVES: I see.

MR. WALKER: -- there may not be leaks at certain pressures, lower pressures, but the higher you go, it's just going to, you know, squeeze it out. So I know that's what the team probably is doing. They're trying to evaluate that, I have, you know, but it's getting to a stopping point so that you say, I've upgraded it as much as I can, it's good for now, lets get it back in service especially if you need to look at the other pipeline which is 4000.

MS. ACEVES: So is that to say that you think some of these subsequent leaks or whatever you want to call them, were as a result as too much pressure coming in to quickly?

MR. WALKER: No, ma'am. I think, what -- and again, I'm going from what I'm reading so my assumption is they were raising the pressure to get it back to its normal operating, you know, pressure. And so when you do that leaks will show up. The leaks at a lower pressure may or may not, they may be -- they're smaller if you notice the -- some of the language they're non-hazardous which means they're smaller so they're not going to show up until you raise the pressure. That's generally what I think is -- but again, I'm --

MS. ACEVES: Right. So doesn't that mean that -- what I asked the first time, they're not going to show up but there're going to may be there?

MR. WALKER: Well, the general thing is it's an old pipe, it's 60 some years old and yes, it's going to have issues.

VICE CHAIR SCOTT: Mark, please, go ahead.

MR. ROTHLEDER: Is the -- is the problems we're seeing on the pipelines, in your opinion, may be symptomatic of maintenance issues or is it symptomatic of use pattern changes. Are we using the pipelines differently because we're raising lowering pressures in different ways because of the nature of the use of the gas system?

MR. WALKER: Without knowing the extent of SoCal's maintenance records, I would be remiss to opine on that. I would say that at some point the pipes are just old. And regardless of how much you've -- you maintain them and it maybe it's the end of life, you know, 70, 75 years for cathodically-protected steel pipeline is kind of a normal range. As far as the raising and lowering, that's probably not a good thing but I don't know that they've done a significant amount of that it's just usually really more of having to lower it to fix the issues and then trying to get it back up to the normal operating pressure.

VICE CHAIR SCOTT: A question, kind of a variation on the theme, I think that you're hearing from here and it's when I look at the trends that you presented back on your reliability overview slide and their major pipelines back in service within weeks. Are those similar age and made out of the similar things that we can take that information and compare it with the system here?

MR. WALKER: I can get the specifics but the ones to -- I'm specifically talking about is the Enbridge pipeline in

Ohio, I want to say and I don't remember it's a 24 or 30 inch --

VICE CHAIR SCOTT: Or length.

MR. WALKER: -- it's a transmission line and then the two in -- for the Colonial pipeline which I'm familiar because we were out of gas in the south because Colonial pipeline feeds the majority of gasoline to the Southeast. So they had a rupture a year or so ago of a 36 and I'm going from memory and obviously an environmental issue. And we're able to contain it and get, you know, they did whatever they had to do. I think two weeks -- week or two and obviously that one being gasoline got a lot more press and I'm sure they were, you know, motivated to take care of it. And it happened on two lines I want to say, they actually had an explosion very similar to what I think went on 235 but, yes.

VICE CHAIR SCOTT: And one other quick question, you mentioned that the running of intelligent pigs is a good best practice. I'm wondering is that a -- how widespread is that as a best practice?

MR. WALKER: Well, that's a good question, it's become more of the approach especially if you have pipelines that actually can handle the pigs because the largest issue with not using them is that basically the pipes are either to small or they have the wrong size bends so the pig can't make the turn to be -- not be funny but it can't fit so you'd use whatever method fits the threat.

And I believe in the case of these pipelines it’s external corrosion which means it’s an outside issue it’s not an internal issue but the pigs are -- the easiest way to get a lot of data then having to, you know, dig up parts of the pipeline. You do the pig and then you do the validation which confirms or denies that what you saw on the, you know, the report is correct and then you do your -- you know, you do your assessment remediation on that.

To one thing to that because it is more popular, one issue I know for the gas company is the scheduling -- the time of those because there -- they have to basically -- they don’t have -- they’re not going to have their own, these are expensive, so the contract with the company sometimes you have to wait in line and so that could be a problem.

VICE CHAIR SCOTT: Reiko.

MS. KERR: When you suggested potentially reducing the pressure on the pipes would that necessarily mean an increase use of inventory fields?

MR. WALKER: It’s all apart of the hydraulic model and why parts and pieces you have to use. At some point as you’ve heard today you will have to use storage because these are the critical pipelines that feed the L.A. Basin and when they’re down there’s not too many other choices. So you’ll probably more likely have to.

MS. KERR: Thank you.

MS. ACEVES: Do you have any other examples on accountability or complia -- or measures that other states have used within the family but still keeping --

MR. WALKER: Well, that's an inter -- and I hesitated to even use that word because it sounds kind of procolomus but I think was is -- comes down it was more of a collaborative approach to come up with a measure that makes sense and -- agree with what is it that will be an accountability metric. To say, you know, what -- so there's not really a, like a regulation or a set rule that has been I've seen. It's been more of a collaborative, you know, we expect to do this. The one I mentioned about taking a pipe out of rate base was the one that the Georgia commission used against us because we were slow in replacing a lot of our pipes.

But a lot of it is more like in Rhode Island, they've set around the table and said, okay, what are you going to do? What can you do? You got 7000 people out of service, a month is not acceptable, what is it going to -- and so they worked out a schedule, collaboratively came up with what date worked and they stuck to it and it was for, you know, the good of making sure that everyone in the community knew that they were, you know, they're on the same page.

And so I don't have a real straight answer on that one and again, I hesitate to set it in there because I know that it's not something that has teeth but I think it can be done, I really do. And I think this is a time in California for the folks that are in the room to come together and figure out a way to do it.

VICE CHAIR SCOTT: Great and on that note. Matthewson and Rod, thank you so much for your excellent presentations and for being here. We're glad to have you.

MR. WALKER: Thank you.

VICE CHAIR SCOTT: Let us now turn to Panel 5 as they're making their way down, this is the update from Southern California Gas Company on Summer of 2019 Technology Assessment Demand Response and New Gas Hookups.

And while we're doing the transition, I'll just do the reminder again for the blue cards. If you're a member of the public and what to make a comment, please go ahead and fill out the one of the blue cards, give it to our public advisor or to Heather and they'll give it to me and that's how we know that you'd like to speak with us.

So welcome come on up. We'll get going in just about 30 seconds here, when they're seated, when everyone's seated.

Okay. Welcome, so we will start with David and Jennifer. Please take it away. Yes, of course, please go ahead.

MR. CHO: Just to do some intros and -- my name is

Jimmy Cho, I'm the Chief Operating Officer for SoCalGas and we brought a pretty broad team together here so we can be responsive to your questions and inquiries. Allow just a quick intro. Mr. Neil Navin is our Vice-President of Gas Transmission Storage. Jennifer Walker is our Director of what we call Gas Control but essential when you hear the term system operator, that would be Jennifer's area. And then Dan Rendler runs our Major Customer Programs, which includes energy efficiency and also demand response that we're going to be talking about today. And then David Bisi is actually probably the smartest one of the group here, he's been a long-term system planner on the transmission system.

And what we're going to do is actually go through the two presentations but I wanted to just say a few statements, the information that we're going to share today is public. Because these assets are highly market sensitive, we will be limiting our comments and information to what's public and certainly our regulators can request additional data from us and we'll respond but I wanted to put that out there.

And also, real quickly, I just want to clarify for your consideration a couple of items shared previously, I do want to make note that the pipeline integrity in San Bruno were not, they're not coupled, pipeline integrity was actually in existence as early as 2003, San Bruno resulted in unfortunately in an incident but also the piece of pipeline safety enhancements.

And the company, I believe has been pigging as early as the 2000s and 2005 on this line in particular. The last thing I'll mention is pigging or inline inspection is like any technology that is evolving the way I think about is cell phones where around as early as the 1990's they're around today but they're vastly different.

The first generation of pigs were what I call low frequency, low resolution tools and today they're much more sophisticated but these are inferential tools where as more data's collected and confirmed, we make them smarter. So I just wanted to throw that out there before I turn it over. Thank you.

VICE CHAIR SCOTT: Thank you and thank you all for being here. You have to turn on your mic, please. Just little button in the front there.

MR. BISI: There it is. Good afternoon. My name is Dave Bisi, I'm the Gas Transmission Planning Manager for SoCalGas and SDG&E. And I'm going to talk to you a little bit about the summer outlook for this coming season.

Next slide. So SoCalGas looked at a couple bookends for the summer season, what we've turned the best-case scenario and a worst-case scenario and that really had to do with which pipelines were assumed to be in service and at what capacity levels.

Under the best-case scenario, we found that we have sufficient receipt capacity to fill our storage fields for the upcoming winter season and be able to meet the forecasted peak summer demand without the use of Aliso Canyon. In terms of send out capacity that worked out to at least 3.5 BCF per day of demand that we could support.

Under the worst-case scenario, we would have insufficient receipt capacity to serve both summer customer demand and to fill the storage for preparation for the winter season.

We could meet the summer peak day demand with Aliso Canyon, but without Aliso Canyon the capacity falls to about 3.0 billion cubic feet per day.

Next slide. This is the summer peak day demand forecast it's the same total number that you saw in the CEC's presentation, we're estimating it at about 3.4 billion cubic feet per day. This assumes average summer core demand as well as EG demand from the 2018 California Gas Report. And as I've stated we have sufficient capacity under the best-case to serve about 3.5 billion cubic feet per day, but we fall short under the worst-case scenario without Aliso Canyon.

Next slide. So what are these best-case and worst-case that I've been talking about? As you know the existing condition is Line 235 is out of service for repairs and Line

4000 is scheduled for outage for validation digs.

In the best-case scenario and we're looking at the summer peak period of around August when we expect that peak demand to hit, we would have Line 235 and Line 4000 return to service and operating at a reduce pressure, plus, we would have sufficient gas supply at the Otay Mesa receipt point to fully utilize the southern zone receipt capacity of 1210 million cubic feet per day.

Under a worst-case scenario, both Line 235 and Line 4000 are removed from service, they're unavailable, and we have reduced gas supply available at Otay Mesa reflecting actually historic performance.

Next slide. Numerically this is what the two bookends look like. The Blythe system under the best-case scenario is full at 1210 million cubic feet per day, that's dependent upon receiving 230 million cubic feet per day from the Otay Mesa receipt point. North Needles, Topock, and Kramer Junction are both capable of receiving supply of approximately 1.2 billion cubic feet per day. Wheeler Ridge is fully available at 765.

Under the worst-case scenario, Blythe still has the capacity to receive 980 million cubic feet per day but Otay Mesa's dropped down to only 150, that's the historical delivery that we've seen.

Because Line 235 and Line 4000 are both assumed to be out of service, we have no receipt capacity at North Needles or Topock but that allows us to receive a bit more supply from Kramer Junction because it's not competing for pipeline capacity with those supplies coming from the east. Wheeler Ridge, we still have left at 765.

Now, what we've done for both of those cases is recognize that customers don't deliver 100 percent utilization, they don't fill the pipelines up to their maximum capacities consistently. What we've seen historically when we have a lot of receipt capacity, they fill it up to approximately 85 percent. That was the assumption we applied to the best-case, because we're at the 3.2 BCF level.

However, what we've see recently when we have little receipt capacity or less, receipt capacity we have more frequent OFOs because customers don't have as many choices, they fill those pipelines up to a higher level, so we assumed a 95 percent utilization for that worst-case scenario.

On top of that, we've put on the same 70 million a day of supply for California local production that's what they're actually producing at the moment. That give us a range of 2.8 -- 2.5 to 2.8 billion cubic feet per day of supply.

Next slide. Now, while we have enough supply, we believe to meet our peak summer demand except for the condition where we have worse-case without Aliso Canyon, that's only one part of the summer operation. The other critical part of summer operation is filling our storage fields, in preparation for the winter season.

Under the best-case scenario, we believe that there's enough supply and capacity to fill our storage fields to sufficient levels, to meet -- to be prepared for the winter season.

Under the worst-case scenario, however, because we have so little receipt capacity available and there's local summer demand, we're not able to fill our fields to what I feel is an adequate level for the sum -- for the winter season. Even if we assume, we're going to get 95 percent utilization for the entire time through the summer season, that -- we would only increase the November starting inventory point by about 18 BCF, still well short of where we've been in the past winters.

Next slide. Retaining and restoring receipt capacity. We have made a 150 million cubic feet per day of supply available at the Kramer Junction receipt point on -- as available basis throughout the issues with restoring Line 235 and Line 4000 to service.

Last summer SoCalGas reached tentative agreements with the Morongo Band of Indians to renew the rights of way for Line 5000 and Line 2000 across the reservation. That preserved a big chunk of receipt capacity on the SoCalGas system.

We're also have completed necessary remediation work on Line 3000 to bring it back in to service. And while that currently did not increase the receipt capacity for the Northern zone due to Lines 235's outage and Lines 4000's lowered operating pressure, it did give our customers another supply choice to bring their gas supplies in to the system.

And we are working to have both Line 235 and Line 4000 in service prior to the winter season in November.

Next slide. Our maintenance outlook, I know we've talked about this already today, but SoCalGas is obligated to perform high and low inventory shut-ins now at its two storage fields -- at all its storage fields, all four.

The low inventory tend to happen at the start -- at the end of the winter season and the start of the summer season. They take about one to two weeks each, I need to make a correction on the slide there that says two to three weeks, it's actually about one to two weeks each per field.

So that's about a month of injection capacity that is lost as you're putting these fields through their low inventory shut-in. That represents about ten percent of the time in the summer season, there's only about 214 days of injection capacity in the formal summer season.

We also have ILI, In Line Inspection, required on several major transmission lines which may impact pipeline and storage supplies. We’re going to do Line 235 in North Needles and we have posted 11 updates since the year began regarding Line 235.

Line 4000 and 4002 south of Cajon Summit pressure limiting station, will be performed in August and September on the northern zone and Line 225 in the Whee -- on our Wheeler Ridge zone system will be performed in June and July. And that could impact supplies from Wheeler and Honor Rancho.

Next slide. Maintaining summer energy reliability. SoCalGas will continue to coordinate operations with CALISO and the LADWP as you’ve heard today. We’ll continue to use OFOs and the -- Aliso Canyon consistent with the Aliso Canyon protocol which included curtailment of non-core customer demand. And maintenance will continue to be schedule during periods of low demand except for safety issues or regulatory requirements. Thank you.

VICE CHAIR SCOTT: Thank you. We’ll let you finish your presentations unless there’s burning questions and then we can turn to questions. Okay. Great.

MR. RENDLER: Okay. Good afternoon. I’m Dan Rendler for those on the WebEx -- this SoCalGas and today my presentation will have two parts, the discussion on demand response -- gas demand response then also new meter hookups.

Can you go to the next slide? So before we jump in to winter demand response, I thought it would be helpful to recognize that the foundation that we feel for demand response is really our energy efficiency programs and so if we look at that as kind of our base effort. We're very pleased to be leading within the state for gas therms saved.

And so for the last five years we've saved in excess -- our customers in excess of 148 million therms and just as an example that would be about 345,000 homes for the year, or 167,000 vehicles off the road.

And so jumping in to our demand response program, at the direction of the commission and we've started back in 2016/17 and you can see there that the first round was really looking at a, what we call the SoCalGas advisory, which was a mass market notification campaign and we started our smart thermostat during January or so of that winter so it's a very kind of front end of it.

In 2017/18 we refined a bit, our program particularly the smart thermostat program for demand response and you can see 9200 customers and about 10,000 thermostats and that's because some homes have two thermostats per home for the difference.

And then in the 2017/18 winter season, we actually had 13 events called between February 20th and March 2nd.

Move forward to 2018/19 last winter season and we continued our smart thermostat load control program, we also had at that time increased our thermostats to 40,000 -- 40,000 customers, 46,000 thermostats enrolled and during that time period we also had 29 events. So you can see the kind of continuation and increase in number of participants in the program.

And then the other thing we had done as well, was in 2018 we did a gas water heater control demonstration, so it was done in a lab not in out at an actual site but to look at actually controlling a water heater similar to the way we're doing the furnaces.

So this is just a quick snapshot of the program and how it operates. So the first step is really to look at lowering the thermostats by up to four degrees during system stress. So it's a 4 degree window, that window was basically established with in partnership with our thermostat manufacturers and looking at what would be a reasonable amount of adjustment that -- if we adjust it too much people would bypass, you don't adjust it enough does it really help. So and then the DR events last up to four hours, so 9 -- 5:00 a.m. to 9:00 a.m. in the morning and or at 6:00 p.m. to 10:00 p.m., it's a little bit later slide. I'll note that we've have tested both those morning and afternoon or evening time periods to see, you know, what type of response we would get.

And then finally, as far as the incentives go, participants receive a $50.00 incentive for enrolling and the

$25.00 for remaining in the program through the winter season and that means not, you know, not opting out. So in other words some customers, and I'll show you some statistics in a minute, actually, you know, stay in the program but they can override the thermostat because it's not a fixed set and they are allowed to do that during the program.

So program recap and this is specifically for last winter season 2018/19 season. So as we mentioned we had 40,000 customers our target was 50,000 and to date we are about 49,000 so we are very close to what we set for target.

We talked about the events that were called between January 1st and February 22nd and this is an example. So the morning events what we found and this is from a previous year is that the morning seem to get a better response from customers.

And then finally, the load impact results, as Mr. Baker mentioned earlier, were anticipating coming up here in the next month but what I can share is that on average about 51 percent of the customers that are on the demand response program actually fully participate in the events and recognizing the significant number of those.

Other things to look at are overrides so we had about 20 percent that overrode either before or during the event, and then we had about 29 percent that actually -- we didn't -- that never got the signal and that could be because their thermostat wasn't on during that time -- something to that nature.

So path forward, I want to acknowledge that there's currently an open proceeding and as a matter of fact there's hearings coming up next week so I'll just touch on the surface, but just wanted to note that we are looking at moving forward. And at the direction of the commission we filed an application back in November and these are the areas that we're looking to identify.

And these are pilots and so the idea is to look at expand in to different areas and look at how we might continue to provide tools that may be useful for reliability during times of stress.

So the space heating load control pilot just very quickly is looking at enhancing that to also include non-residential operations or non-residential customers as well. And then the water heating load control pilot is looking at taking it from the lab and out working with the manufacturer to -- out actually in to, you know, live examples to look at [indiscernible] control and looking at incentives and structure similar to the space heating.

The load reduction pilot is a CNI effort to look at the, you know, commercial industrial side and look at -- to look at programs that they can do from a volunteer basis.

And then residential behavior DR pilot is looking just that the behavior residential, see what we might do in the way of like electrification, some of the items that are in the areas that are currently being looked at on the electric side as well.

And then we've had a winter notification campaign, you might recognize it as dial it down, if you heard it so we're also looking at how we would continue it with that program as well.

So that's the update on our winter demand response.

Next section is on New Gas Hookups.

And so this is really kind of the framing for the new gas hookups so it, kind of gives you a sense, and I have some slides that provide the actual graphics of this.

But I think the important thing to note on this slide is that based on a third parties evaluation, focused specifically -- or more I'll say directly on housing starts, looking at more of the physical area as opposed to permits as well as looking at our historic actual hookups was kind of the framework and the basis for our forecast. And you'll note there that over 95 percent of our customer hookups are residential and the graphs will show this but we're forecasting for our active residential meters the growth rate of a very, you know, small .8 percent per year over the next five years.

Also, have a chart on the commercial side that -- the commercial industrial side that shows increase there too and that forecast is based primarily on economic drivers particularly like employment. And that particular forecast for the next five years is shown to be declining at a rate of about .045 per year. And then also just noting that our forecasts are weather normalized.

So I know this is bit of an eye chart, and I'll thank who ever turned the years up on end as opposed to sideways, but we wanted to give, like a full picture here of time. And you'll note on there a couple of the double forecast areas, and it's important, this is change in active residential meters, so it's not in volume it's actual meters and looking specifically on the residential side. And this is really graphic representation of what I had mentioned earlier with the .8 increase for five years.

The blue is the forecast and -- or excuse me, blue is the actual and red is forecast and you'll note that active meters grew in 2016 by about 34,000, in 17 by 42,000, and then in 2018 by 33, and we're projecting in 2019 about 46,000. And just to put that in perspective that's 46,000 of about 5.8 million non-resident -- or residential meters.

The next slide here gives some information on volume and again this is new customer usage forecast for 2019 to 21 and the difference there is that -- and you'll see this on the next slide that I have as well too, but for new customers, you'll see single family of .0335 MMcf per day. That's about .0447, I think it is roughly for existing homes so newer homes more efficient, both the homes themselves as well as the appliance increase efficiency so we've taken that in to account to -- in the forecast.

And so the -- I guess, and kind of in a nutshell here, the increase in forecast for -- on the residential side, it's because of the increase in the number of customers, the hookups, but if you look at this chart it gives the story that over the last several years we've had a very consistent decline in residential use per meter. And we like to acclaim that to a lot of the work that's been done around energy efficiency also the codes and standards and such. So if you look over time in the work -- envelopes of the homes being more efficient as well as the appliances even some awareness of customers and their usages and such.

And then this graph, next graph talks about our commercial industrial customers and it basically shares the same information that I had mentioned earlier about the kind of miner decrease in there and you can see it's fairly all over the board historically.

And this again is based on a third-party evaluation and looking at employment areas as well too and we've just shown it as kind of a consistent decrease. Just as some information here, in 2017 we had about 85 additional active commercial industrial meters and in 2018 it was a reduction of 447 so various reasons of customers moving out of the area, consolidation of businesses things of that nature as well too.

So I think that's my last slide. Thank you.

VICE CHAIR SCOTT: All right. Great. Thank you. Let's turn then to questions and I'm going to start on the WebEx with Commissioner McAllister.

COMMISSIONER MCALLISTER: Well, lets see. I have a series of que -- can you guys hear me?

VICE CHAIR SCOTT: Yes.

COMMISSIONER MCALLISTER: Okay, good. Let's see. I'm -- I don't have everything right in front of me but is -- who should I direct, sort of pipeline safety questions to? I'm not seeing you guys, so it's a little hard to.

MR. NAVIN: This is Neil Navin, you can -- if I can't answer them, I'll defer and answer later but I'll try to make an attempt.

COMMISSIONER MCALLISTER: Okay. Great. Okay, Neil. So do you have insight at this point about why Line 235 was in such poor condition?

MR. NAVIN: Well, certainly we have been running pigs in that line for some time. We did have a pig run and I don't have the date in front of me, so the long and the short answer, I think is we have been examining that line through--

using our ILI technology. We have also recognized that many of the desert lines are in challenging conditions including rocky soil challenges with environmental conditions. So certainly this line has been recognized as a line that requires additional attention.

COMMISSIONER MCALLISTER: Was there a third-party hired to advise you about that?

MR. NAVIN: Well, certainly part of our -- I'm not responsible for our transmission integrity management program per se but we do actually have, as Mr. Epuna mentioned, we have been engaged with consultants including DNV Integral which was a former CEFER to look at integrity issues more holistically.

COMMISSIONER MCALLISTER: You -- sounds like you don't know exactly what they told SoCalGas about the conditions of the line and causes behind it.

MR. NAVIN: No. I do know some of the details so. So certainly, DNV was engaged as the consultant to look at the root cause analysis failure. They did identify the failure as being largely attributed to complex corrosion which I think has been mentioned here before. They participated in laying out then -- those results ultimately formed the basis for the repair program that we've been discussing today. So the selection of segments to be addressed. That work was done in -- certainly in discussion with SED, right from the outset.

There were two other consultants that were mentioned one was Integral. Integral was used to look at the ILI data, I think, as Mr. Cho mentioned, the ILI data the instrumented data is inferential and provides a guideline for where to look and where to assess. Integral was used to look at the family of anomalies that were identified with the ILI runs and those results were then use in a probabilistic manner to identified areas where we should go and look at replacements.

COMMISSIONER MCALLISTER: So PG&E have sections of this line that aren't too far away, is that correct?

MR. NAVIN: That I think is a fair statement, yes.

COMMISSIONER MCALLISTER: Okay. Have you connected with them or compared notes about, you know, similarities and differences, conditions, and condition of pipe and environmental conditions?

MR. NAVIN: You know, I would defer a detailed response to that to our manager of our TEMP program. I know they are in discussions on many issues, that could be one of them. I don't know, myself.

COMMISSIONER MCALLISTER: Okay. One more question about this line for now. Could you describe the nature of the additional leaks, you know, we've talked about leaks on Line 235 and what you think might be causing them, you know, is that dragging things out a little bit, it's making things less certain, I guess, what do you know about that? Or what can you say about that?

MR. NAVIN: Yeah, certainly. So as mentioned the analysis by both DNV and Integral Engineering, the probabilistic analysis of the anomalies led us to select a number of areas to replace the pipe and that was primarily to address those areas that presented a significant risk of rupture. Having repaired those sections, the normal protocol is to re-pressurize the pipe in a stage manner. And that is to say, bring the pressure up, say a third of the way and then ultimately check the line for leaks.

And doing that in a graduated way provides an added measure of safety for those working on the pipeline. As mentioned, we've at this point had seven leaks identified. Each one of -- well, I should say a number of them were identified at different pressure points. First one at a rather low pressure of -- which I don't recall at the moment -- or may not be able to say in public, second one at one of the midpoint pressures and the last one at the higher pressures. So each one of those were identified as we brought the pressure back up to near operating pressure.

COMMISSIONER MCALLISTER: So you have to redo that depressurization and re-pressurization sort of -- every time you -- well, my question would be, is it possible that new leaks will happen when you sort of go through this process again after repairing the leaks that you found the first times? This a repetitive process?

MR. NAVIN: It certainly is possible, though having found seven at this point, generally the numbers would go down. But, however, as you mentioned we have reduced the pressure on the line to near zero in most sections and at this point once we bring the line and re-pressurize it there is a possibility, we will find additional -- minor leaks that may need to be addressed.

COMMISSIONER MCALLISTER: Okay. Let's see. I guess, overall, I guess, I'm wondering how much you spent on the pipeline safety enhancement plan?

MR. NAVIN: I don't have the figure for the overall pipeline and safety enhancement plan at hand.

MR. CHO: Sorry, Commissioner, are you referring specific to the pipeline safety enhancement plan or this pipeline is -- the PSEP is a separate item I believe.

MR. NAVIN: Yeah. May -- I'm sorry, maybe you can rephrase your question. I can certainly hazard -- an answer.

COMMISSIONER MCALLISTER: It would just be helpful to know sort of, yeah, how -- at what pace those monies are being expended and sort of what the scale of the effort is.

COMMISSIONER RANDOLPH: May be you guys could submit that in comments?

MR. CHO: I think we should, yes. Just to clarify, Commissioner, the request I think is for the PSEP -- PSEP itself? That's what I'm hearing?

COMMISSIONER MCALLISTER: I'm sorry, I didn't.

MR. CHO: For PSEP?

COMMISSIONER MCALLISTER: I'm not quit hearing you.

MR. CHO: Oh. I just want to clarify is the question for total expenders around PSEP itself?

COMMISSIONER MCALLISTER: Yes.

MR. CHO: Okay. Well there is a monthly report that is submitted to the commission -- to the CPUC but we will certainly follow up on that.

VICE CHAIR SCOTT: Why don't we do a few questions from in the room and Andrew we'll get back to you. Is that okay?

COMMISSIONER MCALLISTER: Yeah, that's great. I don't want to monopolize it. Thanks a lot.

VICE CHAIR SCOTT: Okay. No, worries, great. Questions in the room?

COMMISSIONER RECHTSCHAFFEN: Do you want to take a chance the opportunities to respond to Mr. Walker's challenge or criticism about -- essentially that these are maintenance problems that you should have anticipated long before the Aliso Canyon storage spill that if you had been more proactive in your maintenance activities you would have found these out before now, given the best practices that started as early as 2001, that's how I'm interpreting his challenge or criticism. He couched it without by saying he didn't know exactly your situation but I do want to give you an opportunity to respond to that.

MR. CHO: Let me -- this is Jimmy, I'll take the first stab at that. The whole premise and foundational framework for integrity management is continuous improvement. Let me move over, its continuous improvement based on what do we know, what more do we know, and what do we do differently as a result of that. So around this idea of TEMP and I believe all of you are aware there's a seven-year minimum frequency of doing the assessment, as an example on some lines will make a determination that the frequency needs to be tighter -- and as opposed to seven years. And then based on hazards of different areas or soil conditions we may make other determinations as well.

So what I want to say is, we are learning, we are getting more information, the tools are getting smarter, and we are improving and enhancing our way of operating and maintaining system. I do not want in any way that to imply that we weren't maintaining because that's not the case at all. The going forward is, we're going to take what's learned and known from the tools that use so far and the RCA from DNV and others, and the idea is to then how do we apply that?

COMMISSIONER RECHTSCHAFFEN: Are you already incorporating lessons you've learned from the root cause analysis to modify either PSEP program, what you're identifying as risks in the SMAP analysis, even how you're predicting how quickly these instant repairs can be done. Because it sounds to me like it's sort of a rolling learning curve where you're finding problems with re-pressurizing the system that you weren't anticipating which is why the dates keep getting pushed back further and further in to the future?

And I -- and Commissioner Guzman-Aceves asked a question which I don't, which you might want to address too, which is, does the fact that you're finding these problems when you're re-pressurizing the system indicting that -- indicate that there are undetected leaks that you just happening to find out because you're re-pressurizing the line but they exist on the system anyway?

MR. NAVIN: So that was a very long question.

COMMISSIONER RECHTSCHAFFEN: I apologize, since I'm an attorney and you're not suppose to answer, it's a compound question so. So you could object.

MR. NAVIN: I will not object. But, I'm an engineer and by training I will hazard a guess, not a guess, I will give you an answer to that. For one thing, I think we are actually learning and changing our practices, you mentioned the PSEP program, Pipeline Safety Enhancement Plan Program, I would say these lessons are more applicable to the transmission integrity management program.

In that -- what we've learned from the 235 incident is that a more holistic view, say probabilistic view of both tool performance and accounting for tool performance, these tools themselves have a certain level of discernment in them. And so accounting for that, the limitations as it were, so both the strength and the limitations of the tools and using that in a probabilistic manner to address areas of corrosion or complex corrosion that is absolutely something that we are using going forward as an additional tool to improve and enhance the TEMP program.

Your second part of the question as I recall, was related to the leaks, I think you turned them on the line and whether we when re-pressuring the line if we found additional leaks, would that infer that we had not found a leak previously?

I think the short answer to that is, no. The longer answer is that there may have been an anomaly that in the second or third pressurization caused the leak ultimately. So as I mentioned in the previous portion of the response, we did use a probabilistic approach to looking at addressing the areas of the line expeditiously as possible rather than say replacing the entire line.

And if you could remind me of the last part of your question?

COMMISSIONER RECHTSCHAFFEN: Well, it was whether or not your given that what you've been finding as you're re-pressurizing the lines whether or not you're -- it's kind of the confidence you have in the dates you're giving us about when the repairs are going to be complete since you continually missed the targets.

MR. NAVIN: Yeah. I would suggest that at this point the purpose of re-pressurizing the lines in stages, is in fact to find any anomalies that may have been unaddressed. So whereas we have seven instances where we found anomalies as part of the re-pressurization those are areas that we can address before putting the line back in to full service.

So in that case I would suggest that that is what we would want to do to find them now rather find them later. As we re-pressure the line, there does remain a possibility every time we cycle the line up and down so relax the pressure on the line and then increase the pressure as we increase the line there is the possibility that we'll find other anomalies that become leaks, but they themselves would be addressed as expeditiously as possible.

VICE CHAIR SCOTT: Yeah. Commissioner Randolph and then we'll go back to Commissioner McAllister.

COMMISSIONER RANDOLPH: I just want to make sure I understand the status of Line 4000. So that has had the in line inspections and you just -- and you need to do the validation digs, then you're going to re-pressurize, and you may end up finding similar leaks as you found in 235, is that the status?

MR. NAVIN: So Line 4000 is actually in operation at a reduced pressure so it's slightly different than Line 235 in that respect. As mentioned, I think, in the previous presentations, once Line 235 comes back in to service, Line 4000 would be reduced in pressure so that we can do validation digs. It was also mentioned that validation digs are often a way to validate the tools performance, so the ILI tools performance by selecting areas to physically look at the outside of the pipe. So to do that we reduced the pressure in the pipe for those working on the pipe.

Once that validation is taken place there will be an analysis, which again it was mentioned in previous presenters, and based on that analysis, the intention would be that if the analysis shows a strong correlation then we would increase the pressure based upon what we know about the line at that time.

COMMISSIONER RANDOLPH: And do you have permits for those validation digs, yet?

MR. NAVIN: Yes. I believe we do. Yes. Thank you.

COMMISSIONER RANDOLPH: Okay.

VICE CHAIR SCOTT: Back to Commissioner McAllister, and then to Mark, and then to Martha.

COMMISSIONER MCALLISTER: Thanks. I wanted to just build on something that Commissioner Rechtschaffen said, what are you doing to speed this work up -- speed the repair work up, I mean, I know there's a process and you have to may be go through -- up to several cycles de and re-pressurization. And there was a question earlier about, you know, hours -- hours and crews. I guess, can you just talk about how, you know, you're going to plan to try to hit the dates that you're expressing?

MR. NAVIN: Certainly. So again, to go back to some previous presentations, we are working the crews 7 or 6 days a week, 12 hours a day, this is a very narrow right of way, so there are logistical -- significant logistical and environmental considerations that we need to undertake while we're doing the work.

At the height of the work we had roughly 250 people in a very narrow area to do work. So there are concerns, there are concerns about working at night, there are safety concerns, there are environmental challenges that we need to be cognizant of including various species of interest.

So we are, as I said working extended days, extended weeks, and whenever we can we look for an opportunity to parallel work. So as was mentioned previously, we were doing work on sections while raising the pressure in other sections to look for additional leaks that might need to be addressed.

COMMISSIONER RANDOLPH: Can I just add to that as I mentioned in my opening comments my chief of staff, Rachel Peterson went down and visited one of the work sites. And it is in fact a very challenging work corridor and location, so sort of moving equipment in and out and people in and out, is a little -- it's fairly challenging down there. So that part makes sense.

And as, you know, Matt mentioned we really kind of pushed the company to say, do you have the maximum number of crews, do you have the maximum numbers of days, and at this point I think I feel pretty confident that they do. They are putting the right amount of resources in the actual work that's going on.

VICE CHAIR SCOTT: Mark.

MS. WALKER: Hi. It's Jennifer. I just wanted to add that there's also opportunities where we wait for permits, we wait for, you know, the dig alert 811 notifications to be done. Where we're prefabbing pipe and we're doing everything we can in the location during the time that we may be waiting for something, you know, like an authorization to begin disturbing earth and what not.

So we're definitely utilizing all the different time opportunities we can to mobilize and get things ready to move as fast as we can once we start and we get authorizations.

MR. ROTHLEDER: I'm just wondering if you've had opportunity to review Table 8 and 9 of the agency assessment and if you have any disagreements or concerns or updates on either the dates or the volumes? And I realize that you may not be able to answer it right now, but if you can answer in comments that would be helpful.

MR. NAVIN: I'll be happy to do that.

VICE CHAIR SCOTT: Commissioner Guzman-Aceves and then Laki.

MS. ACEVES: You know, it's interesting hearing Commissioner McAllister's line of questions I feel like that's where I was a few months ago and having greater appreciation of what is actually happening and how often folks have been attempting to repair this. I kind of evolved to this place where just thinking about the age of this pipe and really asking and asking you really, when is it -- when are you going to get to the point when you're going to say, the pipe itself or some length of the pipe needs to be replaced or decommissioned.

And kind of along the same lines, when is it appropriate, from your perspective to take these costs or certainly take the profit that you're making off of it out of the rate base since it's not really providing that benefit to the rate payers?

So those are three questions but really, I feel like worse-case scenario we're going to get another seven leaks because it seems like something might be wrong with this pipe.

And let me just add a fourth question. Given your probability analysis that you were mentioning, I assume you look at age as a major one. Are you looking at any populated areas where this particular pipeline is going and have you tested those and making sure that we're not missing an opportunity to be safe here?

MR. NAVIN: Okay. I will start with, if I can the populated areas. So the areas of concern, in general, for this pipeline are within the section west of our Newberry compressor station, so as Commissioner Randolph's chief of staff experienced, this is largely in the middle of nowhere, if that's an appropriate term, there's -- there are very few sections if any that have any significant population address close to them.

To address the issue of the probabilistic modeling, probabilistic modeling is not based on age, it's based on the condition of the pipe as it's examined. So it really is based on the physical examination of the pipe with the ILI, instrumented runs. So age is a factor in the condition of the pipe, if that makes sense, the problem is --

MS. ACEVES: But -- excuse me -- that would be assuming that you have that information for the entire system. So you -- do you --

MR. NAVIN: I should -- sorry go ahead.

MS. ACEVES: No. So is that right? Am I understanding right?

MR. NAVIN: So we do have instrumented ILI runs for this pipeline previously. We do intend, I think, it was also mentioned, to provide after the Line 4000 work was taken place to run another pig run on Line 235 and with that, we would do some additional reviews.

As to the issue of rate base, I think, we'll try to respond in comments afterwards, if that's okay? But these are fairly old lines so at this point I don't know if much of any of the existing -- original pipeline is currently in rate base.

MS. ACEVES: And just remind me because usually and may be you guys know this question but usually, we allow you about 40 or 50 years of recovery on it. And how old is this pipeline, is it exceeded the life of that?

MR. NAVIN: This pipeline is from 1957, predominantly.

MS. ACEVES: So it's probably already rece -- it's probably already -- yeah.

MR. NAVIN: Yes. I believe so.

MS. ACEVES: Okay.

MR. NAVIN: I'll defer to Mr. Cho, here.

MR. CHO: I wanted to just, after the commissioner's question on, you had asked about other lines. The DOT has classification for lines based on the environment, the density and so on. So in areas that are populated or more populated, the margin of safety that is put in based on the design factor the pipeline is higher.

And the other thing that we'll have to make a determination on once these lines go back in to operation. As an operator, we'll have to also determine what is that safety margin we want to have in place. So that will be something we'll also decide.

COMMISSIONER RECHTSCHAFFEN: I'm sorry, did you answer, Commissioner Guzman-Aceves question about when do you just decide to replace the lines?

MR. CHO: Let me make one -- the lines that make up the backbone system are just under 4000 miles; this is a section of line that is running parallel with -- between North and South Needles in to -- I'll just call it our gatherings -- our center stations the basin. It's, I think over 200 miles from the station along the Colorado River in to those -- the central city center areas. The area that we're looking at is a, I believe it, Neil, it's a specific section and so that -- I wanted to say that because -- what the question is when are you going to replace the line? The line itself -- even though there's different numbers and segments, it is a very long line but the issues have been noted through the pipeline integrity assessments in a particular area.

MR. NAVIN: Yes. So to continue with Mr. Cho's response, it is certainly looking at the condition of the line, looking at what we can learn from additional ILI run so additional data. There may be a point in the future of which we would say that replacing the sections that have been currently not replaced would be prudent.

VICE CHAIR SCOTT: Laki and then may be a final question from Commissioner McAllister.

MR. TISOPULOS: Yeah. So could you comment on the two observations that we heard from Mr. Walker that pipeline integrity issues identified here -- fixing pipeline integrity issues take year -- takes elsewhere, you know, weeks to months to correct versus years here. So is it because you have to deal with more agencies, more permits, that's one question?

And the other one is, there was an observation that, I think it was -- I can't remember which exactly state -- Rhode Island, if I remember correctly, the dwell pipes scenario -- at -- can you comment on the feasibility, technology versus economic feasibility to have such a thing for this basin?

MR. NAVIN: Well, first I'll take the second part of the question and that is, I think, Mr. Walker, did mention that in fact the 235 failure was in a location where there was two pipelines. So that pipeline actually does have a Line 4000 and a Line 235 running quite close to each other. So in fact, that northern segment -- or section from the Needles receipt point is essentially two lines.

The other portion of the question which is regard to the time to make the repairs, I think also, Mr. Walker acknowledged that each pipeline situation is somewhat different and unique. In this case, we had a significant failure, that significant failure required a root cause analysis, that root cause analysis was really necessary to understand the nature of the failure. So that when we put the pipeline back in to service, we understood what had taken place.

So I will say that that work was done with significant support from the commission through SED and interaction with SED that was very positive during that effort. That effort also led to this probabilistic view of a complex corrosion on this particular segment of the pipeline. That coupled with the challenges of the remote location and other issues have made this a very challenging piece of pipe to replace.

VICE CHAIR SCOTT: Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. Just one more question going back to the non-Aliso fields. Could you give us a status of what's happening at Goleta and Honor Rancho and any obstacles to really -- having those play the role that they need to play, you know, going forward, managing shut-ins and any equipment upgrades you're doing there?

MR. NAVIN: Certainly. It's a rather broad answer, but I'll give it nonetheless. So as has been mentioned previously, the new DOGGR regulations require a inventory verification shutdown and that that be -- that take place at every field, and that take place twice a year. That is a change from previous years so it has reduced the availability of the fields for injection and withdrawal but primarily injections, is the issue at hand.

The fields at the moment, Honor Rancho went through a -- an inventory shut-in, so that is past for this part of the season in advance of the summer. Our smaller Playa Del Rey field also had an inventory shut-in, so that one is taken place. Our La Goleta field, in fact came off of it's inventory shut-in just today, so as of today that shut-in is complete. I should note though also, that the shut-in also included work that included P - S - E - P work, PSEP work, that was specifically related to the pipelines in and out of that field.

So I think it's important to note that a shut-in is important for the DOGGR requirements but it also presents an opportunity for us to do needed maintenance and repair while the facility is out of service for that period of time. So -- go ahead.

COMMISSIONER MCALLISTER: I'm hearing that those will be ready for injections for early summer.

MR. NAVIN: I should be clear, those fields have been injecting gas to date, save for the periods where they were taken out of service. Typically, to maintain reliability we will take one field out of -- in to a inventory verification condition, one at a time. So that we always have at least three of the fields available.

COMMISSIONER RANDOLPH: No. I was just going to -- I just want to make sure we have time to take public comment before we have to start catching airplanes. So.

VICE CHAIR SCOTT: Indeed. So Commissioner McAllister's was going to be the last question. Was that your last question there?

COMMISSIONER MCALLISTER: Yes.

VICE CHAIR SCOTT: Okay. If it wasn't, please feel free to ask another one. Okay. I want to say --

COMMISSIONER MCALLISTER: No. It actually was.

VICE CHAIR SCOTT: Oh. Go ahead.

COMMISSIONER MCALLISTER: No. It actually was.

VICE CHAIR SCOTT: Okay. Excellent. Well, all right, I want to say thank you very much from SoCalGas. We appreciate you being here. And let us then turn to public comment. I just have two here. The first one is Issam Najm, from the Porter Ranch Neighborhood Council. Let me see where would we like people to go? Oh, right here. And you'll be followed by Sarah Rees. So Sarah, if you don't mind coming a little closer that would be great.

MR. NAJM: I'm good?

VICE CHAIR SCOTT: Yes. Please, go ahead.

MR. NAJM: Good afternoon.

VICE CHAIR SCOTT: Good Afternoon.

MR. NAJM: Thank you for the time. My name is Issam Najm, I'm the President of the Porter Ranch Neighborhood Council and I'm here speaking on behalf of the Neighborhood Council representing the people of Porter Ranch. I wish none of you knows me, but you do, and I have been engaged in this process now for three years and I'll be blunt in saying, I'm disheartened by the direction it is taking.

While this is discussed as an issue of numbers and economics. I want you to please remember that there are peoples lives health and safety behind this whole issue. And I know you know that this is what triggered this thing and that's why we're still talking about it.

The problem that I see is that the conversation is not any more about the Aliso, it's about other things in the system that are overshadowing the issue of Aliso, to the point where the CPUC staff is now asking you to change the usage scenarios for Aliso to accommodate the loss of transmission.

And I urge you, not to go in that direction. Having the field changes operation based on OFOs is simple a backdoor for the gas company to use it as it sees fit. And I ask you not to consider that mitigation measure at all.

In 2017, former Governor Brown, directed the Energy Commission to work towards closure of the facility and coordinate with the PUC to achieve closure in 2027. It is a little difficult for the community to see that neither the CEC nor the PUC has taken a formal position on that directive.

Both have been silent on that direction and that directive is critical for us to understand where our future is going to be. So I urge you to take up that directive and, you know, let us have the courage to have an up or down vote on it, but let us hear from you about that directive. Because that directive is the only thing that we are hanging our hopes on.

And we will continue to plead with you to get to that implementation of the closure of the facility. And we realize that it's a big part of the gas system as it has been used. And we appreciate that and that's why in all of our communications with you, we have clearly labeled it.

We're asking for the expedited and responsible closure of the facility. We understand nobody wants to deprive anybody of their gas supply. The problem that we see and I'm sure you see, that as long as Aliso Canyon option is open, they're will not be an incentive for this company to make it work without it.

I urge you to tell them to make it work without it. Set a timeline, they are smart people, they have a lot of resources, certainly more than we do. And I'm confident that they can get to that point, they just enough of incentive to get to that point.

And I also want to say something to your staff and I don't know if they're still in the room. This winter was not the worst winter in the last several years and I will give you two numbers, the lowest day average temperature this winter, composite average temperature in the system was 49 degrees, that is the highest since 2013. It is not the coldest.

The second issue is, which isn't -- a number that we presented in our letter to the commission in March that the heating degree days in this winter were 902, this is the number of degrees below 65 degrees, degree days throughout a winter season and this is from November to February. It's a standard term, the HDD was 902 this past winter. In 2016, 2017 it was 1200. In 2015, 2016 it was 1200.

This was not a bitter winter, this was a wet winter for us, I can tell you that much, but it was not a bitter cold winter.

The problem is not the demand, the problem is transmission and the fact that we're still talking about it after the January session when they told you that it would be done in April. Here we are in May and it's not done, June it's not going to get done. And now we're talking about November.

We need you to set a date. The best date to set is the closure of the field and that will drive everything. And I don't have time to get in to everything else that I want to say but I will stop at this. I urge you to recognize that there is a human factor behind this question and we need that closure date from you. Thank you.

VICE CHAIR SCOTT: Thank you. Our next comment is from Sarah Rees and she's followed by Gene Lee.

MS. REES: Good afternoon. My name is Sarah Rees, I'm an assistant deputy executive officer for Planning here at South Coast Air Quality Management District.

First, I'd like to thank both PUC and CEC on their willingness to engage with South Coast AQMD on planning for transportation electrification needs in our region and the opportunities for collaboration that you've provided us to date.

As an example of this collaboration, is our work to provide input to the electric transportation demand forecast in the 2019 Integrated Energy Policy Report.

I’d like to provide a little context as to why we as an air agency are interested in the issue of transportation electrification. Our region has some of the worst air quality in the nation and we’re facing deadlines in 2023 and 2031 to meet federal air quality standards. To get there, we’ll need to cut our NOx emissions by about a half.

The vast majority of our NOx comes from mobile sources and of mobile sources the biggest contributors are heavy duty engines. Substantially reducing emissions from mobile sources will be the key to cleaning our air.

Not meeting these standards on time will have significant impacts in our region. Our residents will continue to breath the worst smog in the nation and the federal government could impose sanctions including the potential withdrawal of federal highway funds.

To get the needed emission reductions, we expect that zero-emission electric vehicle will need to make up a much larger fraction of our light duty -- of our fleets. Not only our light duty fleets but also our heavy-duty fleets, and off-road engines.

One example, based on a rough preliminary estimate that we've done, we can foresee that we might need an excess of 300,000 zero emission vehicles to be able to obtain our standards and have that in our region by 2030.

This is well beyond any current electric demand planning scenarios we have seen to date and most of those will be the larger engines not the light duty engines.

We also expect that the electric demands on the grid for this large-scale introduction of heavy duty zero emission vehicles may be noticeable different than that of passenger vehicles and is critical to plan for the scale of those demands.

We look forward to continuing to engage closely with both your agencies on this critical issue. Our staff stands ready to support you as you continue your planning efforts to ensure that zero emission vehicle needs in our region are met. Thank you.

VICE CHAIR SCOTT: Thank you. I have a card from Gene Lee. Are you still in the room? All right. Seeing no additional public comment in the room.

Let me turn to see if we have any comment on the WebEx. Okay. I'm seeing that there is no comment on the WebEx either. So with that we will close public comment.

I just want to briefly say, thank you to everyone for your patience with us while we had our little WebEx blimp. I want to thank our panelists today for providing robust data and really great information for us to all wrap our heads around.

Thanks to my colleagues from our sister agencies for taking the time to be here on the dais with me this is wonderful, and also thank you to Laki for hosting us in your wonderful facilities. We really appreciate it.

And I don't know, Commissioner Randolph, do you have any closing remarks.

COMMISSIONER RANDOLPH: No.

VICE CHAIR SCOTT: Okay.

COMMISSIONER RANDOLPH: Thank you very much for running a very efficient and interesting meeting.

VICE CHAIR SCOTT: Indeed. And with that we are adjourned. Thanks everybody.

(Thereupon, the Hearing was adjourned at 3:37 p.m.

--oOo--

REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 3rd day of July, 2019.

Troy Ray

TROY RAY
CER-369

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 3rd day of July, 2019.

Barbara Little
Certified Transcriber
AAERT No. CET**D-520