900

Krause, Erik

From: AMANDA GREEN <asgreen33@yahoo.com>
Sent: Monday, November 20, 2017 4:25 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson repowering Project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 900-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 900-2

Regards,

Amanda Green, Glendale 91204

901

Krause, Erik

From: Amelia Bernays Pitti <rivergatehouse@gmail.com>
Sent: Monday, November 20, 2017 2:06 PM
To: Krause, Erik
Subject: Power plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project. When the world is going green you are taking our wonderful city in the wrong direction. We do not want this power plan. Please consider another path. 901-1
Thank you

Amelia

902

Krause, Erik

From: Amy Jakovec <amy.jakovec@dreamworks.com>
Sent: Monday, November 20, 2017 2:49 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Oppose Glendale Power Plant Expansion

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 902-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 902-2

Regards,

Amy Jakovec, Silverlake and Glendale

903

Krause, Erik

From: White, Amy <Amy.White@warnerbros.com>
Sent: Monday, November 20, 2017 4:35 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Cc: White, Amy
Subject: I am Opposed to Greyson Power Plant Expansion

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 903-1

As a resident of Atwater Village I am concerned this expansion will negatively impact my community and our health. The expansion is not needed in order to properly serve your customers and yet it is being proposed even with the serious environmental concerns that come with it. 903-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 903-3

Regards,

Amy White

Atwater Village, Los Angeles

amy white | executive director | worldwide digital production - theatrical | warner bros. technology |
w: +1 818.977.2004 | m: +1 323.481.9039 | AIM: AEWatWB

904

Krause, Erik

From: Andre Curry <Thecurrygroup@att.net>
Sent: Monday, November 20, 2017 2:50 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 904-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 904-2

Regards,

Andre Curry, Glendale, CA

905

Krause, Erik

From: Andrew Birdzell <abirdzell@gmail.com>
Sent: Monday, November 20, 2017 4:36 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft. 905-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 905-2

Regards,

Andrew Birdzell (Glendale)

Krause, Erik

From: Ann Renken <arenken@gmail.com>
Sent: Monday, November 20, 2017 9:33 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 906-1

California does not need more electricity made unless it comes from clean sources like solar. It is not worth the health risks. We live just a few blocks from Glendale's border and spend a lot of time in Glendale. The added pollution would not make me want to spend more time with my children at local restaurants and parks in Glendale. 906-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 906-3

Regards,

Ann Renken
Los Angeles, 90065

907

Krause, Erik

From: ann shea <annshea@me.com>
Sent: Monday, November 20, 2017 1:19 PM
To: Krause, Erik
Subject: Please reject plans to rebuild the Grayson natural gas power plant

Dear Glendale City Council and Planning Division,

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. 907-1

Thousands of people live and work directly within the Grayson project's impact zone, which includes schools, daycare centers, homes for the elderly and offices. Glendale's air quality is already terrible--it's time to invest in an energy grid that can turn that around. 907-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 907-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 907-4

Sincerely,
Ann Shea
Glendale Resident

908

Krause, Erik

From: Earthjustice <action@earthjustice.org> on behalf of Ann Shea <info@earthjustice.org>
Sent: Monday, November 20, 2017 1:38 PM
To: Krause, Erik
Subject: Please reject plants to rebuild the Grayson natural gas power plant

Nov 20, 2017

Deputy Director of Community Development Erik Krause

Dear Deputy Director of Community Development Krause,

NO TO FOSSIL FUEL

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. 908-1

Thousands of people live and work directly within the Grayson project's impact zone, which includes schools, daycare centers, homes for the elderly and offices. Glendale's air quality is already terrible--it's time to invest in an energy grid that can turn that around. 908-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing.
The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 908-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 908-4

Sincerely,

Ann Shea

Glendale, CA 91201
annshea@me.com

909

Krause, Erik

From: Ana <anafriend1@gmail.com>
Sent: Monday, November 20, 2017 3:25 PM
To: Krause, Erik; Najarian, Ara; Sinanyan, Zareh; Agajanian, Vrej; Devine, Paula; Gharpetian, Vartan
Subject: NO GRAYSON PLANT!!! STOP POISONING EVERY CHILD, WOMAN, and MAN IN GLENDALE and surrounding communities

Lived in Glendale for 40 years, STOP the plans for "Re-powering and expanding Grayson Plant. STOP POISON, STOP the GREED, STOP POLLUTION, STOP the CANCER. You want the death and sickness for generations of people on your hands. Do you want blood on your soul and your children's children's soul. Stop with this madness. NO Grayson Plant!!!! 909-1

Signed,
40 year Resident Anna

910

Krause, Erik

From: Anne Edgar <anne@artifactnonfiction.com>
Sent: Monday, November 20, 2017 9:49 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Repowering Project / Request for Independent Study

Dear Mr. Krause,

As a Glendale business owner and mother of two children attending school in Glendale, I am writing to express my deep concerns about the Grayson repowering project as outlined in the September 2017 Draft EIR, and my opposition to it moving forward without additional study. 910-1

As the daughter of an engineer who worked in nuclear power for a number of years, I am not immediately inclined to put a stop to energy growth and the expansion of job opportunities. However, studies continue to show the future is in clean, or at least cleaner energy. 910-2

We have poured a considerable investment intp solar power for our office building with the hope of savings for our business down the road, and also so that we can contribute to a cleaner Glendale for our employees, ourselves, our children and our community. 910-3

It is our hope that Glendale is also thinking of the future.

Please pause the CEQA process and take the time to commission an **independent** study of clean energy alternatives. As a member of the Glendale community, it would be valuable for this study to include a concise and clearly written top sheet or synopsis of findings so that the community can weigh in knowledgeably. 910-4

Groups such as NREL or E3 with strong clean energy credentials have been recommended by clean energy groups.

Regards,

Anne Edgar

City of Glendale

911

Krause, Erik

From: Annet Torres <annet_e2002@yahoo.com>
Sent: Monday, November 20, 2017 4:46 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Repowering Project.

Re: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 911-1

The project will increase pollutants and air toxics in our city that will harm the health of residents in proximity to the plant. This project ignores the financial risks that will be imposed on Glendale taxpayers unnecessarily. Think of how this will impact our residents, our children and property values and everything that makes Glendale a desirable place to visit and reside in. 911-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 911-3

Regards,

Annet Estrella-Torres

Glendale, CA.

912

Krause, Erik

From: Anthony Zierhut <anthonyzierhut@gmail.com>
Sent: Monday, November 20, 2017 4:25 PM
To: Krause, Erik
Subject: Glendale power plant planned expansion

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 912-1

I live and work within one mile of this plant and I have asthma. This needs much stronger consideration before going ahead. I also own property within a mile of the plant -- if the quality of life is diminished as a result of the expansion, so will my home resale value. I take this very seriously. 912-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 912-3

Regards,
Anthony Zierhut
Glendale, CA

November 20, 2017

RE: Comments on the Grayson Power Plant Repowering EIR

Dear Mayor Gharpetian and Councilmembers:

We the undersigned, members of the engineering, scientific, and urban planning communities, represent a broad spectrum of opinion on sustainability and energy issues facing communities throughout California. We are concerned with the current $500 million proposal by the city of Glendale to repower the Grayson Power Plant to one with increased capacity [267 megawatts (MW) raised to 310 MW], that is again powered by "natural gas" (*i.e.*, methane) at a time when power demand in the City is projected to decline and the state is increasingly regulating fossil fuel power generation. 913-1

The energy markets are currently going through a transformative shift. The scope and scale of state policies on renewables and regulation of fossil fuel generation is growing nearly as rapidly as the price of renewable energy is falling: in the case of solar, the cost for residential, commercial and utility projects declined an incredible 73% between 2010 and 2016. Emerging technologies in energy storage and efficient renewables will further change the industry. 913-2

The continued commitment to power generation by use of a fossil fuel for the thirty-year projected lifetime of this new plant (approximately July 2021 through June 2051) will also come at a time in the world's global-warming trajectory. Reliable, peer-reviewed studies and simulations of the consequences of an average global temperature rise of 1.5 degrees centigrade above pre-industrial levels show that the greater Los Angeles area will be threatened by more severe wildfires and longer periods of drought[1]. At present warming rates, the need to stay within 1.5°C demands immediate and rapid reduction in greenhouse gas (GHG) emissions. These same simulations show that, unmitigated, the Earth will reach the 1.5°C level by 2030, and the 2.0°C level by 2045. And hence, it appears that the upgraded Grayson Plant will go too far in contributing GHS emissions. 913-3

It is also disconcerting that the upgraded Grayson will emit GHGs at levels exceeding the California limit of 75,000 CO_2 equivalent tons/year. The Grayson Environmental Impact Report (EIR) side-steps this increased pollution for Glendale residents by offsetting it with Emission Reduction Credits – a move that will benefit those outside Glendale, while children and the elderly, the most vulnerable members of our community, will breathe more pollution. 913-4

[1] See study published at Geophysical Research Letters – an AGU Journal- http://onlinelibrary.wiley.com/doi/10.1002/2015GL064924/full

We applaud the Glendale City Council in adopting a resolution earlier this year to join other cities in support of the UN Paris Climate Agreement. In keeping with the spirit of the agreement, we urge the City Council to pause further development of the repower and immediately commission an independent Cost-Benefit Analysis of the project. This analysis should include items such as Glendale's deriving renewable power from electrical grids that connect with solar-, wind- hydroelectric-, and nuclear-generated sources; estimating the harm to Glendale citizens by having to breathe CO_2, unburnt/leaking CH_4, and the non-GHG pollutants generated by Grayson; studying the costs of EPA- or state-mandated raising of emission standards for California as we approach the 1.5°C global-warming threshold; and the benefits in saving its residents the burdens of higher electrical bills and costs of a $500 million bond. 913-5

We hope the Glendale City Council will make the right decision to minimize exposure to risk for ratepayers and protect the air quality of the City. These are also imperatives of a science- and fairness-based policy that can deliver on the UN Paris Climate Agreement. 913-6

Sincerely yours,
(names in alphabetical order)

Dr. Arineh Arzoumanian
Engineering Instructor,
Pasadena City College

Alek Bartrosouf
Assistant Regional Planner,
Southern California Association of Governments (SCAG)

Biayna Bogosian
PhD Candidate
Adjunct Professor of Architecture,
University of Southern California

Dr. Ara Chutjian
Research Experimental Physicist
California Institute of Technology (Ret.)

Rafi Halajian
Senior Project Engineer,
Hathaway Dinwiddie

Natalie Kamajian
Associate, Leadership for Urban Renewal Network (LURN)

Richard Ohanian
Robotics Electrical Engineer,
Jet Propulsion Laboratory
Adjunct Faculty of Engineering,
Glendale Community College

Tarenig Topjian
Founder,
Have A Go

Zirair Tourgoutian
Principal/Program Manager,
Standard Engineering and Construction

Erik Yesayan
Manager, Cypress Creek Renewables
Former Chair of Glendale Planning Commission

914

Krause, Erik

From: Arminda Diaz <arminda@d3architecture.com>
Sent: Monday, November 20, 2017 11:08 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 914-1

We do not live in Glendale, but we are Glendale adjacent in Highland Park/ Eagle Rock area but we are susceptible due to proximity. 914-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 914-3

Thank you,

Arminda Diaz AIA
Los Angeles, CA

arminda diaz aia leed ap *bd+c* * *homes*
dbe/wbe/mbe ncarb
www.d3architecture.com

'Everything is walking distance if you got the time...'
-Steven Wright

915

Krause, Erik

From: Armine Mkanyan <armine88mkanyan@gmail.com>
Sent: Monday, November 20, 2017 6:31 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 915-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 915-2

Regards,

[Name] [City]

Sent from my iPhone

Krause, Erik

From: Haroutunian, Atineh
Sent: Monday, November 20, 2017 7:45 AM
To: Zurn, Stephen; Godinez, Christine; Krause, Erik; Haase, Carl (carl.haase@stantec.com)
Subject: FW: existing location of power plant

FYI

Atineh Haroutunian, Public Benefits Marketing Manager • City of Glendale • Glendale Water & Power Department
141 N. Glendale Ave., Level 2 • Glendale, CA 91206 • (818) 548-3381 • aharoutunian@glendaleca.gov

From: Richard Ramirez [mailto:richramirez1@pacbell.net]
Sent: Sunday, November 19, 2017 11:55 PM
To: Avetisian, Varsenik
Subject: existing location of power plant

I just got back from a long vacation and became aware of the proposed upgrading construction of the existing power plant. I have expressed concern to past council members regarding the location of the power facility because it is sited on a state designated liquefaction potential zone on official maps prepared by the
State Geological Survey. I am very familiar with such designations because I was a former member of 916-1
the State Mining and Geology Board that established the policy and law for these hazard areas throughout California. My interest as a Glendale resident that this matter be carefully evaluated by the technical consultants the city hires. The present plant location is in an area of historically high groundwater and unconsolidated alluvial sediments associated with the Los Angeles river.

917

Krause, Erik

From: ben flashman <bflashman@hotmail.com>
Sent: Monday, November 20, 2017 10:30 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara; GlendaleEnvironment@gmail.com
Subject: Fwd: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 917-1

First, I would ask for an independent study of clean energy alternatives to gas for meeting energy needs. Los Angeles is conducting this type of study presently via National Renewable Energy (NREL, under DoE), Glendale should do the same. 917-2

Secondly, operating a new plant will increase (GHG) greenhouse gas emissions which are a known cause of climate change increasing extreme heat days, drought and fires in our region. City Council signed a resolution to support the Paris Climate accord, this is in direct conflict with this agenda. 917-3

Thirdly, the effect on Glendale's air quality cannot be ignored. Our air already fails to meet federal clean air standards. Grayson will generate emissions that will increase several "criteria pollutants," that are known to increase the risk of asthma, cancers, heart disease, kidney disease, and other illnesses. This makes our children and elderly parents, especially at risk. 917-4

Two elementary schools, Franklin and Keppel are within walking distance of Grayson. My son is in a nearby home daycare, less that 2.5 miles away He is three years old and this so this is especially personal to me. His daycare has infants through 5 year olds and what i love most is that they spend so much time playing outside, I do not want to have to leave Glendale to protect my child from poor air quality. 917-5

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 917-6

Regards,
ben flashmam
Los Angeles

918

Krause, Erik

From: BLAIR SINTA (sintablair@gmail.com) Sent You a Personal Message <automail@knowwho.com>
Sent: Monday, November 20, 2017 9:46 AM
To: Krause, Erik
Subject: Grayson Power Plant: Go Away

Dear Mr. Erik Krause,

With residences and schools so close GLENDALE should be responsible for moving to clean energy for the health of its residents.
As a resident of Glendale and a GWP customer, I'm writing to voice my strong opposition to rebuilding and expanding the Grayson Power Plant. Rather than sinking $500 million into a polluting fossil fuel facility, I urge you to seize the opportunity to make Glendale a showcase for clean energy alternatives. The list of concerns with this project is long. 918-1

? Emissions of carbon monoxide, nitrogen dioxide, sulfur dioxide, small particulate matter and other pollutants will increase across the board. This will worsen already bad air quality in an area that houses two elementary schools (Mark Keppel and Franklin), the Disney Creative Campus and Disney Children's Center, the residential neighborhoods of Pelanconi Estates and Moorpark, and popular outdoor spaces such as the John Ferraro Athletic Fields and Glendale Narrows Riverwalk. 918-2

? Greenhouse gas emissions, which are heating up our region and increasing risks of drought and fire, will increase by more than 415,000 tons of carbon dioxide each year. That's an increase of six times over the current levels, and equivalent to adding 90,000 cars to Glendale's roads! 918-3

? The plant would be built in an identified liquefaction zone. That makes the plant itself, and the gas piping and transmission systems, all highly vulnerable to a serious earthquake. Apart from the obvious safety risks, this raises questions about its ability to maintain reliable service in an emergency. 918-4

? Spending $500 million on a single, large fossil fuel plant creates huge financial risks for Glendale ratepayers. With efforts underway in Sacramento to move the state to 100% clean energy by 2045, it's more likely than not that we'll be paying for this plant long after it's been forced to shut down. 918-5

Glendale doesn't even need this much power. Your own reports forecast falling demand for electricity in Glendale. If demand is falling, why would we need to build a plant that increases generating capacity by 33% as this proposal does? 918-6

This project would lock us into legacy technology that harms public health just at a time when the rest of the state is surging forward. I urge you to halt efforts to expand Grayson and commission a study of clean energy alternatives. 918-7

Sincerely,

BLAIR SINTA
1132 NORTON AVE
GLENDALE, CA 91202
sintablair@gmail.com
(323) 646-3644

This message was sent by KnowWho, as a service provider only, on behalf of the individual noted in the sender information.

919

Krause, Erik

From: Brian Gatewood <briantgatewood@gmail.com>
Sent: Monday, November 20, 2017 9:08 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Re: Grayson OPPOSED

Dear Mr. Krause,

I am writing as a Glendale resident, father, taxpayer, and voter to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 919-1

I am a father of two small children. It is appalling to me that Glendale would choose to double down on old, dirty energy that will sacrifice the health of its residents in favor of short term profits. Purchasing carbon credits does nothing for those of us who live here and breathe the air. 919-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 919-3

Regards,

Brian Gatewood

683 Luton Dr, Glendale CA 91206

920

Krause, Erik

From: Briana fesperman <briana.fesperman@gmail.com>
Sent: Monday, November 20, 2017 7:11 AM
To: Najarian, Ara; Krause, Erik; Devine, Paula; Agajanian, Vrej; Gharpetian, Vartan; Sinanyan, Zareh
Subject: CEQA

City of Glendale,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft . 920-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 920-2

Regards,

Briana F. Eagle Rock

921

Krause, Erik

From: Bridget Moloney-Sinclair <ohbridget@gmail.com>
Sent: Monday, November 20, 2017 12:13 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Power Plant

Hello City Council,

I am writing in strong opposition to the expansion of the Grayson Power Plant. My child attends preschool in Glendale and I plan to send my baby there as well. However, the increase in emissions and other health risks would cause me to spend less time and money in Glendale, a city I love. I'm asking you to pause the CEQA process and commission an independent study of clean energy alternatives for Glendale. That is how California is moving as a whole and is better for business and health. Please have this study conducted by an independent group (such as NREL or E3.) 921-1

Please help Glendale stay a SAFE destination for families.

Best,

Bridget Moloney-Sinclair

922

Krause, Erik

From: Britton Rizzio <rizziob@yahoo.com>
Sent: Monday, November 20, 2017 7:16 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson repowering project

Re: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 922-1

My son goes to school right near Grayson and this will not only affect him, but all the children in the area and school. 922-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 922-3

Sincerley,

Britton Rizzio

Krause, Erik

From: Bryan Cooper <BCooper@shedmedia.com>
Sent: Monday, November 20, 2017 12:19 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 923-1

I've lived in Southern CA my whole life and work in Burbank everyday, which is adjacent to this project, so I wish to protect the fragile environment around me. Please do the right thing! 923-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 923-3

Regards,

Bryan Cooper
Clearance Supervisor
Shed Media // Warner Bros.
3800 Barham Blvd. #410
Los Angeles, CA 90068
(323) 904-4680 x1118
(323) 904-4681 - FAX

924

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 2:25:50 PM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Don't sh where you eat**

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 924-1

When pollution is released from a smokestack near a body of water there is a phenomenon called shoreline fumigation. The cold air over the body of water moves inland and when it meets the pollution plume from the stack it pulls the pollution down to ground level resulting in much higher concentrations of pollution in the areas around the plant. 924-2

The EPA doesn't require looking at shoreline fumigation effects when there is no large

body of water within 3 kilometers but Grayson sits across the street from the LA River and an 8 lane freeway. Independent studies show that major geographic changes like a river, freeways, or even transitions from parkland (Griffith) to urban areas can trigger these ground plume effects (https://doi.org/10.1016/S0074-6142(08)60429-5 https://link.springer.com/article/10.1007/BF00120524).

Depending on the direction of the prevailing wind, this would cause the toxic chemicals released by the Grayson expansion to be pulled down to ground level over the Pelanconi, Glendale neighborhood, over nearby major employers like DreamWorks Animation or Disney, or downtown Glendale.

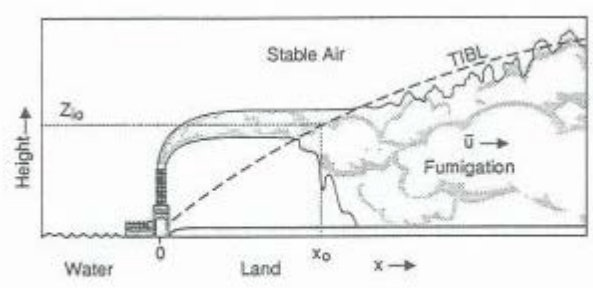

FIG. 1: Illustration of the coastal fumigation phenomenon. The TIBL is shown by the dashed line.

This should make us question the wisdom of increasing the pollution output from a point source that is 600 ft from residences and 1.5 miles from downtown. Why do we want to add to the toxins in the air we breathe? My Dad always says, "Don't sh** where you eat". 924-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 924-3

Regards,

Burt Culver
Glendale

925

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 2:35:12 PM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Transmission Lines

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 925-1

One big argument that GWP makes for the need to build a giant $500 million expansion of Grayson is that they can't put in anymore transmission lines to renewable resources around the state. This is odd since Los Angeles just put one in that opened last year. This line brings in renewable power from Lancaster (see previous post about how they are way ahead of Glendale in renewables). It's too bad Glendale missed out on contracting for a piece of that energy pipeline as an extra 75MW seems to be all that is needed to avoid building a whole new larger plant. Throughout the EIR, Stantec claims that a new transmission line would have a larger impact than a 100% fossil fuel plant without ever running the numbers on the impact or the cost per MW comparison. Also, Stantec claiming that they can't find the right-of-way for a transmission line seems odd since this is the company that did the EIR for the Keystone pipeline which ran across the entire United States! 925-2

Here's an article about LADWP's recent project:

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http://www.ladwpnews.com/corrected-barren-ridge-project-brings-renewable-energy-home/
Barren Ridge Project Brings Renewable Energy Home

The Los Angeles Department of Water and Power (LADWP) held a ceremony today marking the completion of the Barren Ridge Renewable Transmission Project. Consisting of 62 miles of double-circuit transmission line and construction of the 230 kV Haskell Switching Station, among other components, the Barren Ridge project will bring renewable wind and solar energy from the Tehachapi Mountains and Mojave Desert areas home to Los Angeles. 925-2

The clean solar and wind electricity produced by operations in the Tehachapi Mountains and Mojave Desert and delivered by Barren Ridge will power more than 25,000 homes in Los Angeles. Barren Ridge will provide customers access to approximately 1,000 megawatts (MW) of wind and solar power, which include 250 MW from Beacon solar project, 60 MW from RE Cinco solar, 250 MW from Springbok 1 and 2 solar projects, 143 MW from the Pine Tree solar and wind facility, as well as hundreds of megawatts from several of LADWP's hydro-electric plants from the north.

A major component of LADWP's Integrated Resources Plan – a roadmap for transitioning out of coal while maintaining a reliable power supply – Barren Ridge will help Los Angeles meet local and state mandates to reduce environmental impacts associated with climate change and to increase the amount of renewable energy served to customers. LADWP must reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030 and increase the supply of renewable energy – such as wind and solar power – to 33 percent by 2020 and 50 percent by 2030.

"LA is a leader in renewable energy, and implementing projects like the Barren Ridge Renewable Transmission Project is a priority for LA," said LADWP General Manager David H. Wright. "Transforming our power supplies and meeting environmental mandates to help minimize the impacts of climate change are some of the reasons that we needed the recently-approved rate action. This project shows how that greatly benefits Los Angeles."

Mike Webster, LADWP's Executive Director of Engineering and Technical Services said, "This project entailed working in tough conditions in mountainous terrain, but thanks to the hard work of everyone involved, we are able to bring these transmission lines through to deliver more green power to our customers for a cleaner, greener future Los Angeles."

In total the $300 million project consists of the following components:

Expansion of the existing Barren Ridge Switching Station located 12 miles north of Mojave, California;
Construction of the new Haskell Canyon Switching Station in Santa Clarita, California;
Construction of approximately 62 miles of a new double-circuit 230 kilovolt (kV) transmission line from the Barren Ridge Switching Station to the Haskell Canyon Switching Station;
Reconductoring of approximately 76 miles of the existing 230 kV transmission line with larger capacity conductors between Barren Ridge Switching Station and Rinaldi Receiving Station;
And the addition of approximately 12 miles of a new 230 kV circuit on the existing double-circuit structures from the Castaic Power Plant to Haskell Canyon Switching Station.
Construction of the Barren Ridge Renewable Transmission Corridor project is a complex engineering effort that took over eight years to plan, design and construct with the contributions of 400 employees, contractors and other support personnel. The project erected 306 lattice towers and nine monopoles, and used approximately 16 million pounds of steel on towers–enough steel to manufacture 4,000 cars.

For more information, visit www.LADWP.com/barrenridge.

925-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

925-3

Regards,

Burt Culver
Glendale

926

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 2:15:27 PM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Energy Storage Alternatives

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 926-1

The Grayson Environmental Impact Report claims that an alternative battery backup system that would allow us to not build the plant or build a much smaller plant would cost $640/MWh and would therefore be too expensive. That figure is debatable and their math is suspect but the EIR did not look at other solutions like Liquid Air Energy Storage (LAES) which can be installed for $227/MWh. Why not? They are focused on building an over-sized, expensive, dirty power plant and making the ratepayers put up $500 million to guarantee it. 926-2

https://www.utilitydive.com/news/hybrid-compressed-liquid-air-storage-technology-could-be-coming-to-the-us/505660/

Hybrid compressed liquid air storage technology could be coming to the US

926-2

Highview Power Storage is looking to launch its first commercial projects in the next 12 months.

A new, hybrid storage technology could be making its way to the United States, if a U.K. company's plans pan out.

Last month, Highview Power Storage won £1.5 million ($2.03 million) in funding for a new hybrid configuration of its existing Liquid Air Energy Storage (LAES) system from the U.K. government's Innovate UK program.

The funding will pay for the addition of supercapacitors and flywheel technology to Highview's existing 5 MW, 15 MWh LAES facility at Viridor's Pilsworth landfill gas plant in Bury, near Manchester, U.K. That project was the recipient of £8 million ($10.8 million) in funding from the Department of Business, Energy and Industrial Strategy in 2014 and is due to come online by year end.

Quick response

A LAES system has a ramp rate similar to a gas-fired peaking plant. Adding flywheels and supercapcitors gives the system the ability to respond even more quickly to the U.K.'s frequency response market and enables it to layer on more revenue streams, said Richard Riley, Highview's business development manager for North America.

"The next step is to build a complete system," Riley told Utility Dive. The minimum size for a commercial scale LAES plant is 10 MW, which would cost between $40 million and $60 million, he said.

Highview wants to take its technology to that next step, from demonstration to commercial scale, and is looking for projects in the U.S. "The U.S. is probably the most healthy storage market," particularly states such as California, Hawaii and New York, Riley said.

Riley acknowledged that there is a challenge in the U.S.' patchwork of state regulatory regimes, buts said the state of regulation for energy storage in the U.S. is "promising." Energy regulation in the U.K. is slower

moving and more “deliberative,” he said.

While a LAES system itself is new, its component parts rely on existing technology. “A lot of the equipment comes from the oil and gas industry. It is all catalogue equipment,” Riley said. The most expensive component in the system is air liquefaction equipment.

Liquid air storage

Liquid air has been used industrially for decades, but it did not appear as a storage technology until about 2001 when it was developed by Peter Dearman, a garage inventor in Hertfordshire. “Dearman engines” are being explored for use in liquid nitrogen fueled vehicles, including zero emission refrigerated trucks. Highview Power was created to use Dearman's technology for energy storage and move it to the commercial stage.

A LAES system cools and compresses air into a liquid that is stored in what is essentially a giant thermos. When the air is released, it expands rapidly and is used to drive a conventional expansion turbine. To increase the efficiency of that process, the air is heated as it expands. The system also incorporates devices that can store heat from the air liquefaction process and cold from the process of moving the air back to ambient temperature in order to further increase system efficiency.

A LAES system also can be paired with other industrial plants to gain efficiencies by using waste heat and cold. Highview’s 350 kW, 2.5 kWh demonstration project in Slough, U.K., uses waste from a biomass plant. Highview says another application for its technology would be to pair it with a liquefied natural gas (LNG) plant that compresses natural gas into a liquid.

The roundtrip efficiency of a LAES system is about 60%, but Highview says it can boost that up to about 70% by gaining efficiencies from thermal storage or hosting. The biggest cost in operating the system is purchasing power to run the compressors for the initial air liquefaction process. The system also has a parasitic load of about 10%, says Riley.

Compressed air energy storage

In many ways, a LAES system is comparable to a compressed air energy storage (CAES) project or the CAES technology that Hydrostor is tweakingby pumping the air that stores the energy into an underground reservoir instead of an underground cavern.

Among the benefits of those systems are that they have a long life span and longer duration or discharge times than battery storage systems. A LAES system could last for 30 years and can discharge for "tens of hours

or even days," Riley said. The heat loss of energy from the storage tanks is about 0.1% a day, he said. Those systems also can be configured to very large sizes for energy storage, up to hundreds of megawatts.

926-2

That is one of the chief benefits of LAES, Riley said. It can be scaled to very large sizes with very low lifetime costs. That also means that LAES lends itself to certain applications more than others. It would not be good for residential storage, for instance, but could provide peaking power or be used to “chop peaks” or as a non-wires alternative for a substation upgrade, Riley said.

For some applications such as those, “LAES is the lowest cost system that is unconstrained by geography, meaning that it can be located where the value of storage is highest,” Riley said. He cited to Lazard’s levelized cost of energy storage study that put the low end cost of LAES – or thermal storage as Lazard calls it – at $227/MWh compared with $152/MWh for pumped hydro and $116/MWh for compressed air.

Riley said Highview is already “engaging with utilities” in the U.S. for sites and applications for its next installation and hopes to initiate the company’s first commercial projects in the next 12 months.

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

926-3

Regards,

Burt Culver
Glendale

927

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 2:11:45 PM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - PM2.5

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 927-1

Emissions of the ultra fine particulate matter known as PM2.5 is going to increase with an expanded Grayson power plant while new studies are showing a direct correlation between inhaling PM2.5 and chronic kidney disease (CKD) progressing to end-stage renal disease (ESRD). Additionally, this study (http://jasn.asnjournals.org/content/early/2017/09/21/ASN.2017030253.full.pdf) shows "a linear relationship between PM2.5 concentrations and risk of Estimated Glomerular Filtration Rate (eGFR) decline". Therefore, every microgram increase in PM2.5 in the air leads to an increase in chronic kidney disease. 927-2

Glendale is already failing federal air quality levels for PM2.5, we should be reducing emissions of PM2.5 rather than increasing them. At 59.90 ug/m3, we live in the some of the dirtiest air in the nation for PM2.5. The EPA recommended maximum concentration is 12 mg/m3. 927-3

927-3

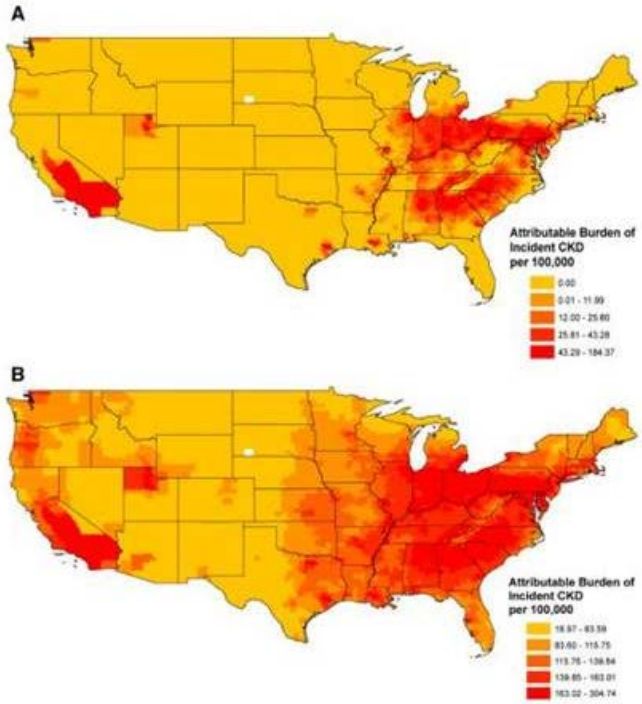

Figure 3. Geographic distribution of the national burden of incident CKD attributable to air pollution in the United States. (A) Risk attributable to exposure levels of $PM_{2.5}$ above the EPA recommended concentration of 12 $\mu g/m^3$. (B) Risk attributable to exposure levels of $PM_{2.5}$ above a uniform distribution between 2.4 and 5.9 $\mu g/m^3$. Burden is per 100,000 population.

927-4

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

Regards,

Burt Culver
Glendale

928

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 1:07:46 AM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Before it's too late

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 928-1

Over 15,000 scientists have signed onto the following warning for humanity to stop business as usual and take drastic action to save humankind. We are the yeast in a bottle, polluting ourselves into extinction. For the future of the planet, Glendale must explore renewable alternatives.

World Scientists' Warning to Humanity: A Second Notice

928-2

Twenty-five years ago, the Union of Concerned Scientists and more than 1700 independent scientists, including the majority of living Nobel laureates in the sciences, penned the 1992 "World Scientists' Warning to Humanity" (see supplemental file S1). These concerned professionals called on humankind to curtail environmental destruction and cautioned that "a great change in our stewardship of the Earth and the life on it is required, if vast human misery is to be avoided." In their manifesto, they showed that humans were on a collision course with the natural world. They expressed concern about current, impending, or potential damage on planet Earth involving ozone depletion, freshwater availability, marine life depletion, ocean dead zones, forest loss, biodiversity destruction, climate change, and continued human population growth. They proclaimed that fundamental changes were urgently needed to avoid the consequences our present course would bring.

The authors of the 1992 declaration feared that humanity was pushing Earth's ecosystems beyond their capacities to support the web of life. They described how we are fast approaching many of the limits of what the biosphere can tolerate without substantial and irreversible harm. The scientists pleaded that we stabilize the human population, describing how our large numbers—swelled by another 2 billion people since 1992, a 35 percent increase—exert stresses on Earth that can overwhelm other efforts to realize a sustainable future (Crist et al. 2017). They implored that we cut greenhouse gas (GHG) emissions and phase out fossil fuels, reduce deforestation, and reverse the trend of collapsing biodiversity.

On the twenty-fifth anniversary of their call, we look back at their warning and evaluate the human response by exploring available time-series data. Since 1992, with the exception of stabilizing the stratospheric ozone layer, humanity has failed to make sufficient progress in generally solving these foreseen environmental challenges, and alarmingly, most of them are getting far worse (figure 1, file S1). Especially troubling is the current trajectory of potentially catastrophic climate change due to rising GHGs from burning fossil fuels (Hansen et al. 2013), deforestation (Keenan et al. 2015), and agricultural production—particularly from farming ruminants for meat consumption (Ripple et al. 2014). Moreover, we have unleashed a mass extinction event, the sixth in roughly 540 million years, wherein many current life forms could be annihilated or at least committed to extinction by the end of this century.

Figure 1.

View large Download slide

Trends over time for environmental issues identified in the 1992 scientists' warning to humanity. The years before and after the 1992 scientists' warning are shown as gray and black lines, respectively. Panel (a) shows emissions of halogen source gases, which deplete stratospheric ozone, assuming a constant natural emission rate of 0.11 Mt CFC-11-equivalent per year. In panel (c), marine catch has been going down since the mid-1990s, but at the same time, fishing effort has been going up (supplemental file S1). The vertebrate abundance index in panel (f) has been adjusted for taxonomic and geographic bias but incorporates relatively little data from developing countries, where there are the fewest studies; between 1970 and 2012, vertebrates declined by 58 percent, with freshwater, marine, and terrestrial populations declining by 81, 36, and 35 percent, respectively (file S1). Five-year means are shown in panel (h). In panel (i), ruminant livestock consist of domestic cattle, sheep, goats, and buffaloes. Note that y-axes do not start at zero, and it is important to inspect the data range when interpreting each graph. Percentage change, since 1992, for the variables in each panel are as follows: (a) –68.1%; (b) –26.1%; (c) –6.4%; (d) +75.3%; (e) –2.8%; (f) –28.9%; (g) +62.1%; (h) +167.6%; and (i) humans: +35.5%, ruminant livestock: +20.5%. Additional descriptions of the variables and trends, as well as sources for figure 1, are included in file S1.

928-2

Humanity is now being given a second notice, as illustrated by these alarming trends (figure 1). We are jeopardizing our future by not reining in our intense but geographically and demographically uneven material consumption and by not perceiving continued rapid population growth as a primary driver behind many ecological and even societal threats (Crist et al. 2017). By failing to adequately limit population growth, reassess the role of an economy rooted in growth, reduce greenhouse gases, incentivize renewable energy, protect habitat, restore ecosystems, curb pollution, halt defaunation, and constrain invasive alien species, humanity is not taking the urgent steps needed to safeguard our imperilled biosphere.

As most political leaders respond to pressure, scientists, media influencers, and lay citizens must insist that their governments take immediate action as a moral imperative to current and future generations of human and other life. With a groundswell of organized grassroots efforts, dogged opposition can be overcome and political leaders compelled to do the right thing. It is also time to re-examine and change our individual behaviors, including limiting our own reproduction (ideally to replacement level at most) and drastically diminishing our *per capita* consumption of fossil fuels, meat, and other resources.

The rapid global decline in ozone-depleting substances shows that we can make positive change when we act decisively. We have also made advancements in reducing extreme poverty and hunger (*www.worldbank.org*). Other notable progress (which does not yet show up in the global data sets in figure 1) include the rapid decline in fertility rates in many regions attributable to investments in girls' and women's education (*www.un.org/esa/population*), the promising decline in the rate of deforestation in some regions, and the rapid growth in the renewable-energy sector. We have learned much since 1992, but the advancement of urgently needed changes in environmental policy, human behavior, and global inequities is still far from sufficient.

Sustainability transitions come about in diverse ways, and all require civil-society pressure and evidence-based advocacy, political leadership, and a solid understanding of policy instruments, markets, and other drivers. Examples of diverse and effective steps humanity can take to transition to sustainability include the following (not in order of importance or urgency): (a) prioritizing the enactment of connected well-funded and well-managed reserves for a significant proportion of the world's terrestrial, marine, freshwater, and aerial habitats; (b) maintaining nature's ecosystem services by halting the conversion of forests, grasslands, and other native habitats; (c) restoring native plant communities at large scales, particularly forest landscapes; (d) rewilding regions with native species, especially apex predators, to restore ecological processes and dynamics; (e) developing and adopting adequate policy instruments to remedy defaunation, the poaching crisis, and the exploitation and trade of threatened species; (f) reducing food waste through education and better infrastructure; (g) promoting dietary shifts towards mostly plant-based foods; (h) further reducing fertility rates by ensuring that women and men have access to education and voluntary family-planning services, especially where such resources are still lacking; (i) increasing outdoor nature education for children, as well as the overall engagement of society in the appreciation of nature; (j) divesting of monetary investments and purchases to encourage positive environmental change; (k) devising and promoting new green technologies and massively adopting renewable energy sources while phasing out subsidies to energy production through fossil fuels; (l) revising our economy to reduce wealth inequality and ensure that prices, taxation, and incentive systems take into account the real costs which consumption patterns impose on our environment; and (m) estimating a scientifically defensible, sustainable human population size for the long term while rallying nations and leaders to support that vital goal.

To prevent widespread misery and catastrophic biodiversity loss, humanity must practice a more environmentally sustainable alternative to business as usual. This prescription was well articulated by the world's leading scientists 25 years ago, but in most respects, we have not heeded their warning. Soon it will be too late to shift course away from our failing trajectory, and time is running out. We must recognize, in our day-to-day lives and in our governing institutions, that Earth with all its life is our only home. (https://doi.org/10.1093/biosci/bix125)

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

928-3

Regards,

Burt Culver
Glendale

929

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 2:41:06 PM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Grayson Museum

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 929-1

SB100 almost passed this year. It's expected to pass next session. It mandates all utilities to be 100% renewable by 2045. If that passes there may be a clause that allows existing plants to live out their useful lives.

If Grayson is started before SB100 passes then it could be one of the last fossil fuel plants running in California. 929-2

Imagine, Glendale could be the last city in the state to be polluting its own air to generate power. Won't our children be proud? Maybe kids will come to visit the Grayson Functioning Museum.

"Yes, kids, people used to poison their own air so that they had electricity."

"But Mrs. Stevens didn't they have solar power?"

"Yes they did Sammy but they didn't have vision."

"Awe, gee, that's sad. <cough><cough> hmm, my throat feels scratchy, Mrs Stevens"

"OK Sammy, no more questions, put your mask back on. Kids, it's time to get going. Glendale is the last city in California to still have childhood asthma, bronchitis, and other pulmonary diseases. That's all thanks to the Grayson Power Plant and the Glendale City Council early this century."

Here's an article about SB100 coming back next session:

http://www.desertsun.com/story/news/politics/2017/09/16/landmark-california-bill-100-clean-energy-unexpectedly-put-hold-until-next-year/670434001/

929-2

"Landmark California bill for 100% clean energy unexpectedly put on hold until next year"

"But both bills are likely to be back next year. California law requires the state to reduce its greenhouse gas emissions 40 percent below 1990 levels by 2030, and state regulators have set a goal of 80 percent by 2050. Meeting those targets will require a massive transition away from fossil fuels, far beyond the 29 percent of electricity that came from renewable energy last year — not to mention a dramatic shift from gasoline-powered cars to cleaner forms of transportation."

929-3

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

Regards,

Burt Culver
Glendale

930

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 12:33:11 AM MST
To: ekrause@glendaleca.gov
Cc: vgharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - the bigger picture

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 930-1

When analyzing the Scholl Canyon biogas project the origin of the gas has a significant impact on the outcome of the environmental impact study. Likewise, we should look at the origin of the natural gas that will be used in the proposed Grayson project. The environmental effects of obtaining that gas is an inevitable consequence of the project. 930-2

Natural Gas (methane) is a dirty fuel. It looks like it burns clean but the process of finding it, obtaining it, transporting it, and burning it leave it on par with coal power.

"Atmospheric methane decays to carbon dioxide and water vapor in about 12 years, but note, carbon dioxide is itself a greenhouse gas, and also, prior to decay — that is, when first emitted — methane is more than a hundred times more potent that CO2. Over a 20-year span, the IPCC considers methane to be 84 times more powerful than CO2. If we keep refreshing the atmospheric supply of methane, as we're doing, we renew its global warming power each year, year after year" (1).

A recent study of the methane leakage of New Mexico's oil and gas operators shows that they are emitting 570,000 tons of methane every year -- equivalent to the climate impact of approximately 12 coalfired power plants. (https://www.edf.org/sites/default/files/new-mexico-methane-analysis.pdf). No similar study of California has been done to date. Also, there is no origin specified for the gas to be burned at Grayson.

In order to get the methane out of the ground, the oil companies use a technique called fracking that has enormous environmental consequences which should also be considered for this proposed project. "Hydraulic fracturing, or fracking, is a method of oil and gas production that involves blasting huge amounts of water, mixed with sand and toxic chemicals, under high pressure deep into the earth. Fracking breaks up rock formations to allow oil and gas extraction. But it can also pollute local air and water and endanger wildlife and human health." "Fracking routinely employs numerous toxic chemicals, including methanol, benzene, naphthalene and trimethylbenzene. About 25 percent of fracking chemicals could cause cancer, according to scientists with the Endocrine Disruption Exchange. Evidence is mounting throughout the country that these chemicals are making their way into aquifers and drinking water. Fracking can also expose people to harm from lead, arsenic and radioactivity that are brought back to the surface with fracking flowback fluid. Fracking requires an enormous amount of water, and because fracking waste water contains dangerous toxins it generally cannot be cleaned and reused for other purposes. Especially during a historic drought, we cannot afford to permanently remove massive quantities of this precious resource from our state's water supply." "Fracking can release dangerous petroleum hydrocarbons, including benzene, toluene and xylene [into the air]. It can increase levels of ground-level ozone, a key risk factor for respiratory illness. The pollutants in fracking water can also enter our air when that water is dumped into waste pits and then evaporates. Air pollution caused by fracking may contribute to health problems in people living near natural-gas drilling sites, according to a study by researchers with the Colorado School of Public Health."(2) 930-2

For a complete picture of the environmental effects of the proposed project, we should look at the full impact of the natural gas used to burn in the plant and not just at the emissions from burning that gas. Compared in this way, once again renewables will be seen as the environmentally preferred option.

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 930-3

Regards,

Burt Culver
Glendale

(1): https://downwithtyranny.blogspot.com/2017/11/new-study-natural-gas-has-no-climate.html
(2): http://www.biologicaldiversity.org/campaigns/california_fracking/faq.html

931

From: Burt Culver <ballast@gmail.com>
Date: November 20, 2017 at 5:47:31 PM MST
To: ekrause@glendaleca.gov
Cc: VGharpetian@glendaleca.gov, "Devine, Paula" <pdevine@glendaleca.gov>, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov
Subject: Grayson EIR - Other Alternatives

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 931-1

The EIR has failed to adequately explore the alternatives of 1) securing additional transmission service from LADWP, 2) adding a small 20 MW unit, and 3) joining the CAISO (Glendale's 2015 Integrated Resource Plan estimates the cost of connecting to the CAISO at $3.2 million/year). 931-2

Additional transmission service from LADWP should be possible under the single contingency scenario (the outage of the Pacific DC Intertie). With additional transmission service from LADWP, or by joining the CAISO, Glendale obtains access to a wide range of resource alternatives and is not limited to local options. There is a major CASIO substation in Eagle Rock that Glendale could tie into fairly readily. 931-3

Additionally, the proposed Scholl Canyon Biogas plant is near the Eagle Rock substation and since they are separate facilities Scholl Canyon could be part of the CASIO balancing authority while Grayson stays within the Los Angeles BA. This would put GWP in the unusual position of having access to two balancing to insure power stability and capability. 931-4

Importantly, for purposes of complying with California Environmental Quality Act (CEQA), all of these alternatives are likely to have lower environmental impacts than building new gas-fired generation in the middle of a densely populated urban area. 931-5

In addition to the option of joining the CAISO, I would suggest the following two resource plan scenarios be considered. Both scenarios retain unit 9 (same as the current plan), but the second scenario would also retain unit 8 (the current plan is to retire unit 8). Both scenarios would retire units 1, 2, 3, 4 and 5 (same as the current plan). Scenario 2 contemplates addition of a new 30 MW unit. However, if due to keeping unit 8 units 1 &2 can also be safely maintained then constructing a 30 MW new unit may not be necessary. The 30 MW battery project is consistent with the EIR which found a 30 MW battery storage facility has been successfully installed in an urban location near San Diego. The development of rooftop solar, although technically "voluntary," can be very successful if promoted by providing incentives to residential and commercial customers. For example, the Net Energy Metering program implemented by the California Public Utilities Commission (CPUC) has resulted in 800 MW of installed rooftop solar PV. 931-6

	Scenario 1:Proposed Resource Plan with 30 MW of Add'l Transm. Service	Scenario 2:Proposed Resource Plan with Existing Transm. Service	Comments
	Resources (MW)	Resources (MW)	
Existing Transmission (200 MW) with Loss of one line (-100)	100	100	From EIR
Unit 9 + Magnolia entitlement	87	87	From EIR
Unit 8	87.2	87.2	From EIR
Battery Storage	30	30	From EIR
Dependable Roof Top Solar	20*	20*	Assumed
Additional Import	30	0	Assumed from LADWP or CAISO
New Unit		30**	May not be necessary**
Total Resources	354.2	354.2	

931-6

*20 MW of dependable rooftop solar PV could mean 40 MW of installed rooftop solar PV capacity

** Retaining unit 8 may allow units 1 and 2 to be retained since they simply use steam from Unit 8 to run their steam-turbines. If unit 1 & 2 are not retired a new proposed 30 MW unit under the second scenario is not necessary.

Any of the plans above meet the city's requirements, are feasible, environmentally superior to the proposed plan, and are more flexible than the proposed plan to the future changes.

Thank you to Jaleh Firooz of Innovative Engineering Solutions for the preliminary analysis that resulted in these options. I've quoted her words at length in this comment.

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

931-7

Regards,

Burt Culver
Glendale

932

Krause, Erik

From: Carissa Kosta <sillycarissa@me.com>
Sent: Monday, November 20, 2017 12:14 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. Pollution has no respect for zip codes. Myself and my two children (6 years and 12 months) all have asthma and are extremely afraid of what this will do to our air quality. We love spending time in Glendale, I had hoped to start preschool for my son there next year, and we have also been looking at buying a home in Glendale, but we will not move forward with a housing purchase or enrollment at preschool if this Grayson project moves forward. 932-1 932-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 932-3

Regards,

Carissa Kosta Koutantzis
Atwater Village, 90039

933

Krause, Erik

From: Jeannette Guerra <jaguerra421@gmail.com>
Sent: Monday, November 20, 2017 4:05 PM
To: Krause, Erik
Cc: vagajanian@glendale.gov; Sinanyan, Zareh; Devine, Paula; Gharpetian, Vartan; Najarian, Ara
Subject: Grayson Power Plant Expansion

Dear Mr. Krause,

As a longtime resident of The City of Glendale, I am concerned by the rapid commercial development, increase in traffic, and now, proposed repowering of our Grayson Power Plant. 933-1

I am advocating on behalf of our Jewel City residents, community stakeholders and our precious environment to City Council members for a environmentally sound repowering of the plant. I am also asking for consideration of alternative energies to fuel the growing energy needs of our City. We should continue to grow in a responsible way imposing minimal burdens to current residents, community stakeholders, and our beautiful City. 933-2

Your consideration is appreciated.

Sincerely,

Jeannette Guerra
817 Palm Drive

Sent from my iPhone

934

Krause, Erik

From: CARLOTA GOMEZ <carlotagomez@sbcglobal.net>
Sent: Monday, November 20, 2017 1:07 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Power Plant

Dear Mr. Krause, I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 934-1 I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 934-2 Regards,

Carlota Gomez
Los Angeles, 90041

935

Krause, Erik

From: Caroline Fraissinet <fraissin@usc.edu>
Sent: Monday, November 20, 2017 10:39 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 935-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 935-2

Regards,

Caroline Fraissinet
Los Angeles, CA

936

Krause, Erik

From: Caroline Keichian <caroline.keichian@gmail.com>
Sent: Monday, November 20, 2017 10:21 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Power Plant - Protect Glendale

Erik Krause,

GWP's upcoming plans to "re-power" and expand the Grayson Power plant with fossil fuel driven energy will pollute our neighborhood air and endanger residents. I work in Glendale down the street from this projected location. I also live 10 minutes away. I want to live and work in any more pollution than our city already lives in. This plant is a horrible idea. We need to be moving forward to cleaning and more renewable energy. Please work to protect our community. 936-1

The effects go far beyond just Glendale. The entire Los Angeles air basin is already failing federal limits. Building Grayson is just going to make the matter worse. Adding that much pollution to the air will impact residents far from the plant and people driving by on I-5 and I-134. Climate Change is happening and it's an emergency. Glendale's greenhouse gas emissions add to the problem. 936-2

Please follow LA's steps and conduct an independent study of clean energy alternatives.

Sincerely,
Caroline

937

Krause, Erik

From: Caroline Orija <corija@antioch.edu>
Sent: Monday, November 20, 2017 8:29 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson Power Plant Expansion-Draft EIR Comment

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 937-1

According to CalEnviro Screen(https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30) the area is already plagued with poor air quality. Although not required, I would like to see Los Angeles County Department of Public Health perform a review of the project. 937-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 937-3

Regards,

Caroline Orija, Glendale, California

--

Best,
Caroline

Urban Sustainability MA
Antioch University, Los Angeles
corija@antioch.edu

938

From: Papazian, Eliza
To: Krause, Erik
Cc: Godinez, Christine; van Muyden, Gillian
Subject: FW: STOP POWER PLANT REBUILD PROJECT
Date: Monday, November 20, 2017 4:49:47 PM

Eliza Papazian | City of Glendale | Management Services
613 East Broadway, Suite 200 | Glendale, CA 91206 | (818) 548-4844 | epapazian@glendaleca.gov

-----Original Message-----
From: Carolyn West [mailto:mjpcomacho@gmail.com]
Sent: Monday, November 20, 2017 8:08 AM
To: Devine, Paula; Gharpetian, Vartan; Najarian, Ara; Garcia, Michael; Kassakhian, Ardashes; Sinanyan, Zareh; lfriedman@glendaleca.gov; Jurca Catherine; Agajanian, Vrej; tghs@glendalehistorical.org; Hardgrove, Daniel; A'Hearn, William; hedgegraphics@earthlink.net; eradley@aol.com
Subject: STOP POWER PLANT REBUILD PROJECT

We are totally opposed to the Grayson Power Plant rebuild plan. This needs to be stopped immediately. GWP has spent time and money working on plans that lacked community input, failed to examin alternatives, are antiquated, are environmentally harmful, lack innovation, etc. Contact Mayor Bill Peduto in Pittsburg, PA and ask him about the need to get smart, cut greenhouse gases, etc.!! This power plant is in our backyard here and next to our river. We are not going sit still. 938-1

Note: this is not the first example of city time and resources being expended before getting community input. This resulted in big wastes of taxpayer dollars. Two others a year back were: Riverside Dr. sidewalk project and project to demo craftsman bungalows at 128 & 132 S. Kenwood and put in another new multi-story apt. bldg. 938-2

From: Carolyn West, Member Glendale Rancho Neighborhood Association

939

Krause, Erik

From: Cheyenne H <starringme@sbcglobal.net>
Sent: Monday, November 20, 2017 9:58 AM
To: Krause, Erik
Subject: Glendale Power Plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 939-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 939-2

Regards,

Cheyenne Renee Haynes, Glassell Park

940

Krause, Erik

From: Chris Ell <chris.ell@dreamworks.com>
Sent: Monday, November 20, 2017 1:22 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Opposition to Grayson Repowering Project - Think Green!

To whom it may concern,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 940-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 940-2

Regards,
Chris Ell (Glendale Resident)

--
Christopher Ell - Themed Entertainment
P: 818.695.4715 - C: 323.472.0931

941

Krause, Erik

From: Chris Liang <coldcashc21@hotmail.com>
Sent: Monday, November 20, 2017 4:09 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 941-1

As someone who suffers from asthma and just moved to Glendale, I want to be able to live in a clean city. 941-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 941-3

Regards,

Chris Liang
Glendale, CA

942

Krause, Erik

From: Christine Della Cioppa <cdellacioppa@gmail.com>
Sent: Monday, November 20, 2017 8:33 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson Power project as outlined in the September 2017 Draft EIR. 942-1

My husband and I live in Highland Park with our 3.5 year old son and our 1 year old daughter. Please do not poison our babies lungs with this power plant. There are plenty of better renewable options for energy that do not effect the health of your communities. 942-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 942-3

Regards,
Christine Della Cioppa
Highland Park

943

From: Papazian, Eliza
To: Krause, Erik
Cc: Godinez, Christine; van Muyden, Gillian
Subject: FW: NO on Grayson
Date: Monday, November 20, 2017 4:31:42 PM
Attachments: image001.png
image002.png
image003.png
image004.png

Erik, your email was spelled incorrectly. Please see below.

Thank you,

Eliza Papazian | City of Glendale | Management Services
613 East Broadway, Suite 200 | Glendale, CA 91206 | (818) 548-4844 | epapazian@glendaleca.gov

From: Cielo Ruiz [mailto:cielorruiz@gmail.com]
Sent: Monday, November 20, 2017 9:48 AM
To: ekraus@glendaleca.gov; Najarian, Ara; Sinanyan, Zareh; Agajanian, Vrej; Devine, Paula; Gharpetian, Vartan
Subject: NO on Grayson

Dear Erik Kraus and the Glendale City Council,

I don't even know why I would need to send an email regarding the issue of not re-opening the Grayson power plant, because it would seem obvious that the citizens of Glendale would NOT want it opened. As our city council, I would think you would be making decisions that would best benefit the public, but here I am, needing to write to you to let you know that I do not want to breathe in 700% more air pollution than I already do. Living in Los Angeles, alone, I'm breathing in so much pollution, why would I want to breathe in more? Health insurance isn't easy to come by, and the last thing I need is the government making me sick. Think of the children and their developing lungs, the elderly - everyone - who's health would be affected by this. Think of your own health and your family's health. If anything, make decisions and take action on developing CLEANER air, or creating clean air projects. It's 2017, I think that makes way more sense with all the technology, research and information that we have. 943-1

Make the right decision and STOP the Grayson power plant from re-opening. It's your ethical and moral duty to do right by the people. 943-2

Sincerely,

Cielo R. Ruiz
719 Highland Ave.
Glendale, Ca 91202

944

Krause, Erik

From: Cindy Bajarias <cbajarias@gmail.com>
Sent: Monday, November 20, 2017 1:49 PM
To: Krause, Erik
Subject: Power plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 944-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 944-2

Regards,

Cindy Tolosa, PASADENA

945

Krause, Erik

From: Claudia Rose <claudia@claudiarose.net>
Sent: Monday, November 20, 2017 9:28 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 945-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 945-2

Regards,

Claudia Rose
Glendale, CA

946

Krause, Erik

From: Collin Erker <collinerker@gmail.com>
Sent: Monday, November 20, 2017 2:05 PM
Subject: NO to the Grayson repowering project

Dear Representative,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 946-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 946-2

Regards,

Collin Erker
Glendale, CA

947

Krause, Erik

From: Earthjustice <action@earthjustice.org> on behalf of Cynthia Rodriguez <info@earthjustice.org>
Sent: Monday, November 20, 2017 1:39 PM
To: Krause, Erik
Subject: Please reject plants to rebuild the Grayson natural gas power plant

Nov 20, 2017

Deputy Director of Community Development Erik Krause

Dear Deputy Director of Community Development Krause,

Thank you for reading my letter.

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. 947-1

Thousands of people live and work directly within the Grayson project's impact zone, which includes schools, daycare centers, homes for the elderly and offices. Glendale's air quality is already terrible--it's time to invest in an energy grid that can turn that around. 947-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing.
The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 947-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 947-4

Sincerely,

Cynthia Rodriguez

Glendale, CA 91205
cyn_1222@hotmail.com

948

Krause, Erik

From: Daniel Sinclair <sinclairoil@gmail.com>
Sent: Monday, November 20, 2017 10:06 AM
To: Krause, Erik
Subject: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 948-1

My children attend the Glendale Montessori School on Doran Street, which is located about a mile away from the Grayson Power Plant. I am deeply concerned about the air quality and additional health risks that would hurt my family due to the expansion. Please consider our community's health and well being over the potential energy benefits. 948-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 948-3

Regards,

Daniel Sinclair
Burbank

949

Krause, Erik

From: Daniella D. Lodge <danielladaher@hotmail.com>
Sent: Tuesday, November 21, 2017 7:02 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 949-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 949-2

Regards,

Daniella Lodge

Sent from my iPhone

950

Krause, Erik

From: Dave Lewis <deucecoupe67@gmail.com>
Sent: Monday, November 20, 2017 1:41 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara

Dear Ladies and Gentlemen,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 950-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 950-2

Regards,

David Lewis, Glendale, CA

Krause, Erik

From: David Gudino <davidcolcs2000@gmail.com>
Sent: Monday, November 20, 2017 4:25 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Re: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 951-1

As a concerned resident of Glendale this potential project will place the health of loved ones and mine in jeopardy. 951-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 951-3

Regards,

David Gudino

City of Glendale

952

Krause, Erik

From: David Mollison <davidmollison1@gmail.com>
Sent: Monday, November 20, 2017 5:06 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Hi Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 952-1

I live in Mt Washington, 90065 and my family, the local school and all those residents will be stuck up in the smog layer if you increase pollution. 952-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 952-3

Regards,

David Mollison
Creative Director

+1 310 623 2477
www.davidmollison.co.nf

953

Krause, Erik

From: Derrick Nau <derricknau@gmail.com>
Sent: Monday, November 20, 2017 5:00 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Sinanyan, Zareh; Najarian, Ara; Agajanian, Vrej
Subject: Grayson Plant Expansion Feedback

Hi All,

Thanks for offering a public comment period.

I'd like to voice my opposition to the expansion of the Grayson Plant. 953-1

I would much prefer to see green energy solutions in the future for Glendale. 953-2

I live in Glendale and I'd like to see our community be a leader in clean energy, rather than looking back at nonrenewable energy sources. 953-3

Thanks,

Derrick Nau

611 N Howard St
Apt 225
Glendale, CA 92106

--
Derrick Nau | Texture & Look Development Artist

Production Sessions Coordinator
ACM SIGGRAPH 2018 Vancouver

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954

Krause, Erik

From: Diana Diekmann <diforfitness@gmail.com>
Sent: Monday, November 20, 2017 4:53 PM
To: Krause, Erik
Subject: GWP dirty fossil fuel

As an Echo Park resident, I am against expanding the power plant and the dirty fossil fuel driven Grayson power plant. DO NOT DO IT!! 954-1

Diana Diekmann

Krause, Erik

From: Diana <dianacmathieu@gmail.com>
Sent: Monday, November 20, 2017 9:45 AM
To: Krause, Erik
Cc: Agajanian, Vrej
Subject: Grayson are-powerful MG Project

Dear Mr. Krause,
I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 955-1

I have been a resident of Glendale for over 20 years and we plan on staying here and raising our 9 year old daughter. We enjoy living in Glendale and worry that with the expansion there will be too many pollutants in close proximity to our daughters school. It is the responsibility of the elected officials to put the population before business. 955-2

GWP emphasizes that the new equipment is cleaner burning than the old, and they're right about that. But they are using the opportunity to expand production by so much that emissions of greenhouse gasses (GHGs) and air pollutants will actually go up. And not just a little. The fine print in their public report shows that the new plant will increase GHG emissions by 415,000 metric tons CO2 equivalent per year. That's like adding 90,000 cars to Glendale's roads. And that doesn't include the effects of methane emission leaks in the process of fracking, transporting and storing the gas. At the same time, emissions of smog-producing criteria pollutants - like CO, NOx, SOx, and small particulate matter - are all increasing over current levels, as are air toxics that cause cancer, kidney disease, cardiovascular disease, low birth weight, and other problems. And they're asking us to pay $500 million for the privilege. And guess what? Even as they expand production, they are publicly forecasting that electricity demand in Glendale will decline over the next 15 years. So this is not about meeting future needs. It's about generating excess power to sell into the market in order to pad the city budget. The upcoming California Renewables Portfolio Standard (RPS) 2030 deadline mandates that all publicly owned utilities including GWP procure 50 percent of their electricity from eligible renewable energy resources. The Grayson repowering project does nothing towards that goal. The power generated by the proposed Grayson plant would be 100% dirty. As a resident and a taxpayer, I find this unacceptable! 955-3

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 955-4
Regards,Diana MathieuGlendale, Ca

Sent from my iPhone

956

Krause, Erik

From: Dien Huynh <dien_huynh@hotmail.com>
Sent: Monday, November 20, 2017 4:25 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 956-1

I feel strongly that Grayson Repowering Project selected mainly because it's more cost effective is not the right decision. A renewable/clean energy solution must be implemented here. We must be conscientious about environmental impact. Sometimes, we must make difficult decision to save the environment for our children. We have an opportunity to make an impact to our environment, let's do it right. 956-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 956-3

Regards,

Dien Huynh, Glendale CA

957

Krause, Erik

From: Earthjustice <action@earthjustice.org> on behalf of Donn Christensen <info@earthjustice.org>
Sent: Monday, November 20, 2017 4:09 PM
To: Krause, Erik
Subject: Please reject plants to rebuild the Grayson natural gas power plant

Nov 20, 2017

Deputy Director of Community Development Erik Krause

Dear Deputy Director of Community Development Krause,

Thank you for reading my letter.

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. 957-1

Thousands of people live and work directly within the Grayson project's impact zone, which includes schools, daycare centers, homes for the elderly and offices. Glendale's air quality is already terrible--it's time to invest in an energy grid that can turn that around. 957-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing.
The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 957-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 957-4

Sincerely,

Donn Christensen

Azusa, CA 91702-6281
donn.christensen@gmail.com

958

Krause, Erik

From: donna sole <donnasole@hotmail.com>
Sent: Monday, November 20, 2017 11:44 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 958-1

I live on Highland Avenue and myself, as well as my daughter suffer from severe asthma and by building this type of plant so close to our home will only cause us significant asthmatic attacks and many trips to the Emergency Room. Also think about how many children suffer from asthmatic attacks, and this plant is situated so close to Mark Keppel elementary, Toll Middle, and Hoover high school. This plant needs to be stopped. It will also bring down our value of our homes. 958-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 958-3

Regards,

Donna Sole, Glendale CA

EARTHJUSTICE

959

November 20, 2017

VIA ELECTRONIC MAIL

Erik Krause
Interim Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, CA 91026-4386
ekrause@glendaleca.gov

Re: Comments on the Draft Environmental Impact Report for the Grayson Repowering Project

Dear Mr. Krause:

In accordance with the California Environmental Quality Act (CEQA), we submit these comments on behalf of the Sierra Club on the Draft Environmental Impact Report (DEIR) for the Grayson Repowering Project (Grayson Project).

The Glendale Department of Water and Power (GWP) proposes a project that demolishes the whole Grayson Power Plant, including all its ancillary buildings, with the exception of the recently constructed Unit 9. Following demolition, GWP proposes to build an entirely new 278 Megawatt (MW) natural gas-fired power plant.[1] This new power plant will consist of four separate turbine blocks as well as an array of support and ancillary buildings and equipment. This new power plant will be 43 MWs larger than the current power plant and is a significant expansion beyond the plant currently at the site. For context, the California Independent System Operator (CAISO) estimates that 43 MWs is enough energy for 32,250 households.[2] There were roughly 71,500 households in the City of Glendale in the 2011-2015 time period.[3] 959-1

[1] Stantec, Draft Environmental Impact Report Grayson Repowering Project, September 15, 2017, at 2.2 (hereinafter "DEIR").
[2] California ISO, Glossary http://www.energy.ca.gov/glossary/ISO_GLOSSARY.PDF
[3] United States Census Bureau, Quick Facts: Glendale, CA https://www.census.gov/quickfacts/fact/table/glendalecitycalifornia/HSD410215#viewtop. The DEIR notes that GWP has "88,100 electric customers." DEIR 2.8.

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With the addition of the new Grayson Project, GWP will have a total generation capacity of 328 MWs at the Grayson site.[4] 959-1

While it seems cost of this undertaking has not yet been finalized, the current estimate is half-a-billion dollars ($500,000,000). This estimate is already $160,000,000 more than the highest estimated provided by GWP in 2015 when it sought approval from the City Council to proceed with a new 250 MW power plant at the Grayson site.[5] Further, it is unclear how accurate this half-a-billion dollar cost estimate is because GWP would not provide details about how the estimate was constructed, about what is included in the estimate, we do not know how accurate assigned costs are.[6] While the cost of the power plant is not an environmental impact, understanding the projected cost is critically important here because cost is used as a basis for rejecting cleaner alternatives to the Grayson Project. 959-2

Overall, the DEIR reveals that GWP has failed to undertake the type of through analysis required by CEQA prior to approving this project. Instead, this DEIR minimizes the real and significant environmental harms that will result from building this power plant in order to make it easier to avoid scrutiny from the public and to get approval from the Glendale City Council.

In contrast to the process unfolding here, the fundamental goal of CEQA is to ensure that decisionmakers, including the public, have complete information about the environmental impacts of a proposed project before its approval. This core informational aspect of the DEIR is important to ensure the long-term protection of the environment. At the core of this effort is the Environmental Impact Report that the Courts describe as "an environmental alarm bell whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return."[7] Here, the DEIR fails to meet this core requirement as it proposes to build a massive fossil-fueled power plant, claiming that doing so is the only possible way to meet Glendale's energy need and claiming that the brand new 959-3

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[4] "As shown in Table 2-1, the Project includes replacing 235 MW gross (219 MW net) of generation capacity with 278 MW gross (262 MW net) of generation capacity. The Project would increase the total Grayson Power Plant generation capacity from 286 MW gross (267 MW net) to 328 MW gross (310 MW net), for a net increase of 42 MW gross (43 MW net)." DEIR 2.2.

[5] City of Glendale, Report to the City Council, Agenda Item: Integrated Resource Planning Report, June 2, 2015, at 4 (hereinafter June 2015 Report to Council).

[6] Letter from Christine A. Godinez to Angela Johnson Meszaros dated November 8, 2017, stating that "the budget estimate for the Grayson Repowering Project is $500 Million" but declining to provide details of the estimate, stating "Please be advised that preliminary drafts, notes, or interagency or intra agency memoranda are withheld pursuant to California Government Code § 6254(a)."

[7] *County of Inyo v. Yorty*, (1973) 32 Cal.App.3d 795, 810

Grayson Power Plant will have no significant environmental impacts. Such a determination flies in the face of facts about environmental and health impacts of fossil fueled energy. Further, the DEIR rejects clean energy alternatives that could meet the city of Glendale's energy needs without adequately exploring the feasibility of those alternatives. 959-3

CEQA does not mandate any particular outcome, but it does require that decisionmakers are fully aware of the environmental consequences of the decision being made. CEQA also requires that GWP avoid or reduce environmental damage whenever feasible by requiring changes in a project through the use of alternatives or mitigation measures. It is, therefore, unlawful for an Environmental Impact Report (EIR) to hide or conceal environmental impacts of a proposed project. Similarly, it is unlawful for an EIR to stack the deck in favor of project approval by obscuring the true scope of the project and its environmental impacts. The DEIR runs afoul of both the spirit and the law regarding disclosure of environmental impacts. 959-4

I. The project's description is inaccurate because it fails to disclose that Grayson has been sized to allow Glendale Water and Power to sell energy to the energy market.

An accurate project description, including the project's objectives, "is the *sine qua non* of an informative and legally sufficient EIR," while an inaccurate or incomplete project description "draws a red herring across the path of public input."[8] The court will reject an EIR with an inaccurate or incomplete project description. 959-5

The Grayson DEIR lists nine objectives for the Project, all of which focus on meeting Glendale's energy needs. For example, objective number two is "Utilize current and reliable technology and control systems to provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load."[9] Purportedly, the Grayson DEIR's proposal of a new 278 MW power plant is based upon Glendale's need. However, it is clear from looking at information developed prior to the Grayson DEIR that the DEIR is hiding from the public important information necessary for understanding the massive size of this fossil fueled project: selling the energy produced by an over-sized power plant.

In 2015, the City of Glendale developed an Integrated Resource Plan Report (IRP). The IRP purported to "provide a roadmap for future resource decisions for GWP."[10] The document also included many references to the fact that rebuilding Grayson will cause the GWP to have more energy than needed to serve Glendale's energy needs. The IRP suggests that excess energy could be sold to offset the financial risk associated with the overbuild.

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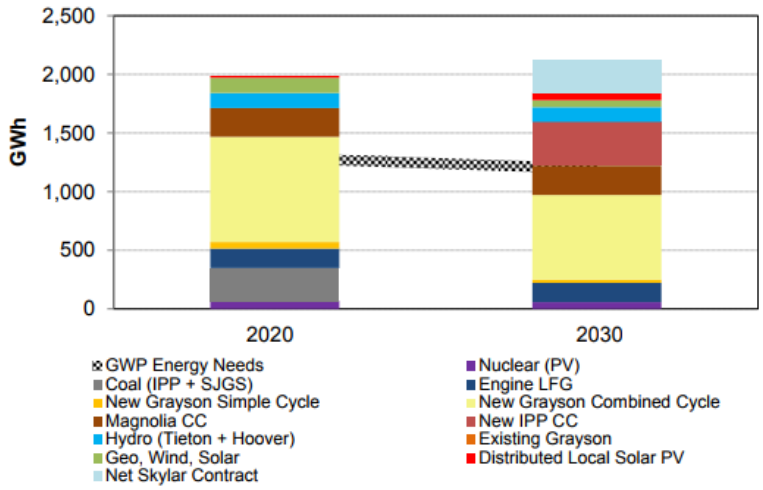
[8] *County of Inyo v. City of L.A.* (1977) 71 Cal.App.3d 185.
[9] DEIR 2.15.
[10] Pace Global, 2015 Integrated Resource Plan Report, June 30, 2015, at 6 (hereinafter "IRP"). This is the most recent IRP that GWP has developed.

For example, a graph showing the "projected portfolio energy resources over time" demonstrated that in 2020 and in 2030 GWP's "energy needs" will be far, far below the proposed energy portfolio that includes a 250 MW Grayson power plant.[11] Indeed, the IRP specifically points out that "notably, GWP's energy resources are projected to be greater than its needs, meaning that excess sales opportunities are likely to be available."[12] 959-5

Exhibit 2: Projected Portfolio Energy Resources over Time



Note that the "Net Skylar Contract" and refers to Skylar's obligation to deliver to GWP minus GWP's obligation to deliver back to Skylar. Further detail on this contract is provided in the GWP Situation Assessment chapter of this report.

Source: Pace Global analysis

Indeed, the IRP summarized the "preferred resource plan strategy" related to Grayson as:

> Proceed with a re-powering of the natural gas-fired Grayson Power Plant with a combination of simple cycle and combined cycle combustion turbines totaling around 250 MW, pending further engineering study. Find a long-term municipal partner to contract for a share of the new plant's capacity and energy in order to reduce market exposure associated with potential excess energy sales.[13]

And the "summary of key metrics for preferred resource plan" noted in the "risk" section that "since there is a larger reliance on excess energy sales, a partner for long-term offtake of

[11] Of course, the proposed Grayson Project is for 262 MWs, even more than was contemplated in the IRP.
[12] IRP at 7.
[13] IRP at 6.

capacity or energy is recommended in order to mitigate the risk of relying on short-term, spot markets."[14]

In conducting the portfolio analysis to compare various Grayson repower options, the IRP writes: 959-5

> As can be seen, the portfolios with new combined cycles at Grayson have the capability to produce more energy than is required for meeting GWP's native system needs, opening up the opportunity for revenues from sales of surplus power.[15]

Then, the IRPs "summary of portfolio analysis findings" reports under "risk" performance metric that "the 250D portfolio offers a hedge against high market prices, but relies heavily on market sales, suggesting that a long-term offtake agreement may be recommended."[16] And under the "financial flexibility" metric that "the 250D portfolio requires the highest capital expenditures and new debt. However, a contract arrangement with an offtaker could provide security in future revenue."[17]

In its final summary of the portfolio analysis, the IRP notes "the 250D MW option has the highest capital investment but lowest range of costs; it has highest reliance of off-system sales in order to keep costs down."[18] Another way the IRP summarized this was to say: "the larger capacity additions at Grayson require more capital and potentially pose a risk to GWP's financial stability."[19]

It is strikingly clear from the IRP that the 250 MW option produces far more energy than is needed to meet the GWP's energy needs. It is also clear that under the "environmental stewardship assessment" metrics—which looked only at emissions of CO2—the 250 MW scenario was the worst environmental performer—as would be expected. For example, the IRP

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[14] IRP at 8.
[15] IRP at 47.
[16] IRP at 52.
[17] IRP at 52.
[18] IRP at 52.
[19] It is not at all clear who the buyer of all of this surplus fossil energy could be or whether the price, if a buyer were to be found, would be sufficient to justify the high capital cost of the new fossil facilities at Grayson. Indeed, both the California Public Utilities Commission and the California Independent System Operator have found that a large surplus of natural gas plants currently exists and that this surplus will only grow in the future as the state increases its use of renewable resources. See, e.g., Ivan Penn and Ryan Menezes, Californians are paying billions for power then don't need, Los Angeles Times, February 5, 2017, (http://www.latimes.com/projects/la-fi-electricity-capacity/). *See, generally*, California's electricity glut, Los Angeles Times (http://www.latimes.com/projects/la-fi-electricity-glut/)

acknowledges that "portfolios with more energy generation…also produce larger amounts of CO2."[20] And the "summary of portfolio analysis findings" notes for "environmental stewardship: Portfolios with more local generation have the highest CO2 emission footprint."[21]

959-5

Interestingly, the DEIR confirms the fact that all the energy from the Grayson Project is not critical to meeting Glendale's energy need by providing two pieces of information: Grayson's construction schedule and plans for contracting with the Los Angeles Department of Water and Power (LADWP) during construction. The DEIR explains:

> The demolition at the Grayson Power Plant would commence in the second quarter or early in the third quarter of 2018, and be completed in the first quarter of 2019. Construction of the Project is scheduled to commence during the first quarter of 2019.
>
> In order to facilitate the Repowering of Grayson, Los Angeles Department of Water and Power (LADWP) has agreed to assist GWP during the repower Project in accordance with the following terms; Term – up to eight years beginning January 1, 2015, Delivery at Air Way receiving station, *Quantity up to 75 MW during peak period hours and up to 25 MW during off-peak hours, to ensure that the City will have sufficient electrical energy to serve its customers.*[22]

Here, the project description is inadequate because the DEIR fails to explain that the project has been sized to do more than simply ensure that that Glendale can meet its energy needs, rather, its size is driven by the ability to sell excess energy from the power plant.[23] Further, despite the IRP's conclusion that a 250 MW power plant would exceed Glendale's energy need,

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[20] IRP at 52.
[21] IRP at 52.
[22] DEIR 3.45. (emphasis added)
[23] The DEIR argues extensively that GWP has an obligation under federal law to generate enough energy to serve all of Glendale's need at a level of the highest peak usage plus 100 MW to allow for the loss of the single largest source of energy, which is loss of a power line. *See, e.g.* DEIR 2.11. However, this requirement actually applies to the Balancing Authority within which Glendale sits—the LADWP Balancing Authority—not to Glendale. As the City acknowledged in response to a question posed seeking clarification about these purported requirements:

> With respect to the single largest contingency (also known as the "most severe single contingency") and balancing authority obligations, the applicable federal reliability standard is WECC Standard BAL-002-WECC-2a. This standard requires the Balancing Authority to maintain a minimum amount of contingency reserves. GWP operates as a metered subsystem within the LADWP Balancing Authority Area. As a metered subsystem, *GWP must either self-provide or purchase from LADWP or other[] regulation and balancing services to balance the loads and resources within its metered subsystem* (i.e. within GWP's service area).

Letter from Christine A. Godinez to Angela Johnson Meszaros, October 26, 2017, at 2. (emphasis added)

GWP proposed a 278 MW power plant with no explanation for the increased size, while construction planning makes clear that without Grayson a maximum of 75 MWs is needed "to ensure that the City will have sufficient electrical energy to serve its customers.

959-5

GWP is proposing to build a power plant that is bigger than is needed to meet the City of Glendale's native energy requirements. Building and operating this large power plant will result in increased environmental impacts beyond what would occur if the DEIR's project was sized to only meet the City's native load. Further, GWP overstatement of Glendale's need facilitates the rejection of clean energy alternatives that would easily meet the actual need had it been properly stated. Because the DEIR hides this underlying objective, the public and other decisionmakers are unable to make an informed decision about the Grayson Project—and resulting environmental impact—rendering the DEIR unlawful.

II. The DEIR improperly rejects feasible alternatives that would reduce environmental impacts while meeting the project's stated objectives

The DEIR "must consider a reasonable range of potentially feasible alternatives that will foster informed decisionmaking and public participation."[24] The DEIR "*shall* include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project."[25] The DEIR has failed to meet this basic legal standard because it constructed alternatives that do not truly inform the decisionmakers and the public about reasonable, feasible, and available clean energy alternatives that would significantly reduce or eliminate environmental impacts of the Grayson Project. Further, the DEIR failed to support important assertions of fact including assertions about the costs of alternatives as compared to the project's cost and the purported need to build more transmission capacity to use less polluting energy alternatives.

959-6

a. Clean Energy can provide feasible alternatives to the Grayson Project

There was a time, perhaps only a few years ago, when building a new massive fossil fueled power plant seemed proper for meeting energy needs. That time has passed. Now, the reality that clean energy choices can reliably and cost-effectively meet both capacity and peaking needs has been established. As a result, a DEIR that dismisses clean energy alternatives with the scant consideration given here fails to meet the information requirements of CEQA was well as the environmental protection goals that CEQA mandates.

959-7

[24] Guidelines 15126.6(a).
[25] Guidelines 15126.6(d). (emphasis added)

First, because the DEIR overstates Glendale's energy need, all of the alternatives are improperly drawn. The alternatives available to meet a 75 MW peak need are very different from those available for a 278 MW project to meet Glendale's energy need and to sell energy. 959-7

Second, recent changes in California law combined with three recent examples in the Southern California region highlight the reality of the shift to clean energy.[26] California's adoption of SB 350 in 2015 requires utilities to get 50 percent of their energy from renewable energy sources and double energy efficiency savings by 2030.[27] Of critical importance here, all of the IRP scenarios modeled Glendale's alternatives based upon reaching a 33 percent renewables mandate by 2030, not the 50 percent mandate established by SB 350.[28] This mistake alone requires the DEIR to completely reanalyze all the alternatives at 50 percent renewables. Also, last year, the legislature nearly passed SB 100, which would have established at 100 clean energy target by 2045 and accelerated SB 350's 50 percent mandate to 2026 and changed the 2030 mandate to 60 percent. SB 100 will be taken up again in 2018. All indications are that California will only increase and accelerate its renewable mandates and the Grayson Project will hinder, rather than support, Glendale's efforts to comply with these mandates. 959-8

i. The California Energy Commission is proposing the reject a fossil fuel power plant license application because the identified energy need can be met with clean energy.

In 2015, NRG submitted an Application for Certification for the proposed Puente Power Project (P3). The 271 MW power plant was to be located on the existing site of the aging Mandalay Generating Station. NRG sought certification for the project after P3 had been chosen by Southern California Edison to fill a local capacity need identified by the California Independent System Operator (CAISO) for the Ventura/Santa Barbary County region. After more than two years of an intense licensing proceeding before the California Energy Commission (CEC), the Commissioners conducting the proceeding issued a statement 959-9

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[26] GWP's assertions in the DEIR that building Grayson increases, rather than decreases, its ability to integrate renewables is unsupported by any analysis and conflicts with the analysis in the DEIR about Glendale's energy portfolio. In particular, the DEIR shows that if GWP builds Grayson it alone would be sufficient to meet Glendale's energy needs almost every day of the year. This means that almost every day of the year *every* MW of renewable energy will be in excess of Glendale's energy need. Put another way, almost every day of the year Glendale's ratepayers will be paying for energy that they do not need, cannot use, and Glendale will not be meeting California's mandate to meet its energy need with renewable energy.

[27] Clean Energy and Pollution Reduction Act of 2015 (https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350); see also California Public Utilities Commission, Implementation of SB 350 (http://www.cpuc.ca.gov/sb350/)

[28] IRP at 47.

informing the parties that "it intended to issue a [proposed decision] that recommends denial of the Project."[29] This proposed denial came after CAISO released a study[30] demonstrating that clean energy resources, including battery storage and other clean energy resources "are technologically feasible to meet local capacity requirements" in the area.[31] CAISO also pointed out that the only way to really know the cost of deploying feasible clean resources is by putting out a Request for Offers to receive bids for providing those resources.[32] As a result, the CEC has granted NRG's request to suspend the P3 project application for six-months pending the outcome of a new process by Southern California Edison and the Public Utilities Commission to identify available, cost-effective clean energy resources to meet the energy need in the local area. 959-9

This stunning shift from meeting an identified energy need with Puente's 271 MW fossil fueled power plant to a process to identify clean energy sources to meet that need shows how dramatically the energy landscape has changed. California energy regulators understood that moving forward with P3 in the face of the state's focused efforts to address climate change and move the state to clean energy means making choices today that do not lock us into more fossil fuel powered energy.

ii. The Los Angeles Department of Water and Power has paused its plans to rebuild its natural gas plants to fully explore how to meet energy needs with clean energy.

The Los Angeles Department of Water and Power (LADWP) has known since 2010, when the State Water Resources Control Board approved the policy to eliminate the use of ocean water to cool power plants, that it would no longer be able to avoid the need to retire its aging coastal power plant fleet. It determined that it would replace every megawatt of the existing energy capacity with a new fossil fueled fleet of power plants and began a $2.2 billion capital effort.[33] This year, LADWP decided to "put on hold all planned local repowering projects until a 959-10

[29] California Energy Commission, Committee Statement Regarding the State of the Presiding Member's Proposed Decision (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221401_20171005T173308_Committee_Statement_re_PMPD_Status.pdf)
[30] California Independent System Operator, Moorpark Sub-Area Local Capacity Alternative Study, August 16, 2017. (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN220813_20170816T165328_Moorpark_SubArea_Local_Capacity_Study.pdf)
[31] Letter from California Independent System Operator to the California Energy Commission, September 29, 2017. (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221345_20170929T153404_CAISO_Comments_regarding_Puenete_Power_Project.pdf)
[32] Ibid.
[33] Los Angeles Department of Water and Power, 2016 Briefing Book at 12. (https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB423407&RevisionSelectionMethod=LatestReleased)

system-wide, in-depth, and independent study/analysis is conducted to analyze the necessity for repowering [and to] identify all viable alternatives to repowering."[34] 959-10

iii. Southern California Edison launched a successful Preferred Resources Project to avoid building a natural gas plant to serve the energy need of more than 250,000 residential and 30,000 commercial customers

In 2015, Southern California Edison launched a project to meet a projected 300 MW of load growth in Orange County without building a fossil fueled power plant.[35] The first phase of this plan, called the "Preferred Resource Pilot" secured roughly 40 percent of this target with a mix of "Preferred Resources"--including battery storage, demand response, and solar—to "meet the needs of a metropolitan area, delivering the energy that is needed, when it is needed, and for as long as it is needed."[36] More solicitations are planned. 959-11

b. The DEIR improperly rejected the alternatives

CEQA requires an in-depth discussion of each alternative and its impacts in a way that the public and decisionmakers can undertake a meaningful comparison with the proposed project. "An agency may not approve a project unless it finds the alternatives are infeasible, a finding that must be supported by substantial evidence in the record."[37] 959-12

The DEIR proposes four alternatives in addition to a "No Project" alternative required by CEQA. The four alternatives are Energy Storage Project Alternative (Storage Project), Alternative Energy Project Alternative (Alternatives Project), 150 MW Project Alternative (150 Project), and the 200 MW Project Alternative (200 Project).[38] Ultimately, the GWP rejected each alternative by arguing, that it "failed to meet the Project objectives to the same extent as the Project."[39] The standard for consideration, however, is not whether the alternative meets the

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[34] Los Angeles Department of Water and Power, L.A.'s Clean Energy Future, June 6, 2017. Slide 6. (http://clkrep.lacity.org/onlinedocs/2016/16-0243_misc_8-1-17.pdf)
[35] Southern California Edison, Preferred Resources Pilot, August 17, 2015. Slide 2. (http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205728_20150813T151843_Preferred_Resources_Pilot_by_Caroline_McAndrews_of_SCE.pptx)
[36] O.C. Pilot Tests Whether Clean Energy Resources Can Meet Growing Needs of Major Metro Area: SCE contracts for 125 megawatts of power, including batter storage and solar, September 9, 2016. (https://www.insideedison.com/stories/orange-county-pilot-tests-whether-clean-energy-resources-can-meet-major-metro-needs)
[37] PRC § 21081.5; *Save Panoche Valley v. San Benito County*, 158 Cal.Rptr.3d 719.
[38] DEIR 5.3 – 5.4.
[39] DEIR 5.15.

objective "to the same extent as the Project" but whether the alternative would meet the basic objectives of the project while reducing environmental impacts.

While the DEIR goes out of its way to argue why each alternative purportedly does not meet certain objectives, it does not find that any of the alternatives are infeasible. Indeed, as outlined above, the state of California mandates the use of clean energy to meet energy needs and using clean energy to meet the need previously served by fossil fuel power plants is feasible. 959-12

The DEIR rejects each alternative without adequate evidence to support key assumptions underlying the basis for the rejection. For example, the DEIR provides no support for its bare assertions that there would not be sufficient energy available to recharge the batteries in the Storage Project, which is the primary reason for rejecting that alternative[40], nor is there analysis to support the assertion that new transmission lines are required for the Alternatives Project[41] and the 150 Project, [42] which is the primary reason for rejecting those alternatives. In fact, a recent planning study conducted by the California Natural Resources Agency, called "RETI 2.0," concluded that "confirm[ed] that existing transmission capacity is available to interconnect a substantial amount of new renewable generation in several areas of the state."[43]

The DEIR rejected the 200 Project after acknowledging it would have less environmental impact and "meet most of the Project objectives" because it purportedly is "a higher cost option

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[40] "The Energy Storage Project Alternative is completely dependent on excess energy being available to charge the batteries, primarily through daily imports over the transmission systems. During high load periods, there will not be sufficient excess capacity to charge the batteries thus compromising the ability of this Alternative to reliably serve the residents and customers of the City. While this Alternative, using batteries alone, does have reduced local environmental impacts, it does not meet several critical project objectives with regards to assuring reliability of supply at reasonable cost." DEIR 5.30.

[41] "The Alternative Energy Project Alternative produces less potential air quality, greenhouse gas emissions, hydrology and water quality, and noise impacts than the proposed Project, but it would create greater impacts in several other resource categories because this Alternative requires additional development of transmission facilities on remote site(s); it requires a significantly greater amount of land to be disturbed in connection with development of new transmission line routes." DEIR 5.30.

[42] "This Alternative would create
greater impacts in several resource categories described above because it would require a significantly greater amount of land to be disturbed for the development of new transmission line routes." DEIR 5.30.

[43] Renewable Energy Transmission Initiative 2.0 Plenary Report, California Natural Resources Agency, February 23, 2017, at 9.

than the proposed project."[44] However, the DEIR does not provide sufficient information to support the claim that the 200 Project option is "higher cost" and seems to reach that conclusion by adding "the impact of the cost of periodic battery replacement as well as the need to dispose/recycle the batteries when they reach end of life."[45] This is improper because there is no support for the cost numbers that are included in the DEIR for the 200 Project. Further, the DEIR does not provide *any* information at all about the cost of the proposed Grayson Project, and includes no information about the ongoing operation costs for the proposed fossil fueled power plant. Therefore, not only is a cost comparison between the 200 Project (or any of the alternatives) and the Grayson Project not possible, it seems the DEIR is rejecting the 200 Project on the basis of costs of both construction and operation. This approach adds costs to the 200 Project that are not disclosed for either the Grayson Project or any other alternative rendering this cost approach completely without basis and therefore unlawful. 959-12

In comparing the potential environment impacts of the alternatives as compared to the project, the DEIR finds that *every* alternative, *including the no project alternative*, would have similar or less environmental impact than the Grayson Project, unless a new transmission line is built.[46] However, the DEIR does not provide any meaningful analysis to establish that a new transmission line would be needed and merely speculates about environmental impacts of a transmission line. These unsupported assertions and speculations do not meet the informational requirements found in CEQA law and are not substantial evidence to support the rejection of the alternatives. Strangely, after finding that the 200 Project would have less environmental impact compared to the project, the DEIR declared the Grayson Project to be "the Environmentally Superior Alternative."[47] That declaration, too, is unsupported by evidence in the record.

III. The DEIR Improperly Asserts That Air Quality, Geology & Soils, and Greenhouse Gas Emissions of the New Power Plant Will Be Less Than Significant

a. The air emissions are significant 959-13

As the lead agency, GWP is responsible for determining whether this power plant will have significant air quality impacts. To make that determination, GWP is required to identify a significance threshold against which to compare the emissions from the power plant. In the DEIR, GWP choose to use the South Coast Air Quality Management District's (SCAQMD) daily

[44] DEIR 5.30.
[45] DEIR 5.27.
[46] DEIR 5.29.
[47] DEIR 5.29.

959-13

significance thresholds for operations as the threshold.[48] Every air pollutant GWP analyzed will increase as a result of building this new power plant.[49] Two of the pollutants, Nitrogen Oxides (NOx) and Volatile Organic Compounds (VOCs) clearly exceed the SCAQMDs significance threshold. The significance threshold for both NOx and VOCs is 55 pounds per day, the power plant will have a net increase of 1,475 pounds per day for NOx and 102 pounds per day for VOCs. This exceedance of the significance threshold is clearly presented in the summary chart on page 4.3.34 of the DEIR:

Table 4-26 Project Maximum Net Daily Emissions

Pollutant	NO_X (lbs./day)	CO (lbs./day)	VOC (lbs./day)	PM10 (lbs./day)	PM2.5 (lbs./day)	SO_X Lbs./day
New turbines (without maint.)	648	623	179	173	173	101
New Turbines (with maint.)	1,570	1,017	191	173	173	101
New Emergency Engine	6	3	0.19	0.01	0.01	0.01
New Cooling Towers	0	0	0	5.4	5.4	0
Facility Occupancy	0.58	1.45	0.69	0.40	0.12	0.006
Less: Replaced Equipment (actual historic)	102	497	90	162	162	26
Net Increase (turbines without maint.)	**553**	**130**	**90**	**16**	**16**	**75**
Net Increase (turbines with maint.)	**1,475**	**524**	**102**	**16**	**16**	**75**
Sig. Thresholds (Operation)	55	550	55	150	55	150
Exceed Thresholds	YES	NO	YES	NO	NO	NO
Exceed Thresholds after New Source Review Offsets	NO	N/A	NO	NO	N/A	NO

Note:
1. The net emissions increase does not reflect emission offsets that will be required pursuant to SCAQMD Rule 1302. With the retirement of emission offsets to offset any emission increase of NO_X, VOC, PM10 and SO_X; the net increase of all pollutants will be below the significance thresholds.
2. CO and PM2.5 emissions are not required to be offset per SCAQMD Rule 1302 nor do they exceed the applicable SCAQMD daily mass emissions thresholds.

While it is clear that the significance thresholds are exceeded, the DEIR seeks to confuse the otherwise clear next step in the analysis. Under CEQA, once a project's impacts exceed the significance threshold the proponent must identify that impact as significant. The next step for the CEQA analysis is to seek feasible mitigation measures to avoid significant impacts. CEQA requires that feasible mitigation be adopted. If, after adopting all feasible mitigation, the identified impacts remain significant, then the agency can do a "statement of overriding

[48] DEIR 4.3.33 ("To evaluate the air quality impacts of the Project, maximum daily emissions from the new equipment were compared with the significance daily thresholds for operations.")
[49] This table also misses a key step in the SCAQMD process for determining significance thresholds by omitting the requirement to first reduce historic actual emissions from the existing Grayson power plant to current state of the art pollution control called "Best Available Control Technology" (BACT). This BACT discount significantly increases the "net increase" in emissions resulting from the project. Taking this BACT discount into account may result in PM also exceeding the significance threshold and, therefore, also requiring mitigation.

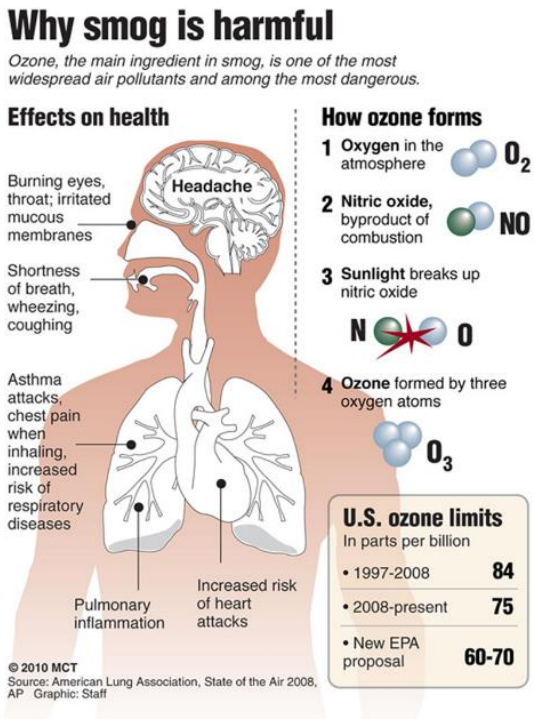
considerations" to explain to the public why the project will move forward despite its significant environmental impact.

959-13

Here, GWP inserted an unauthorized and deeply misleading sub-step to the significance finding: it argues that the project no longer exceeded the significance threshold "after New Source Review Offsets."[50] This sub-step short-circuits CEQAs required process of examining mitigation and alternatives for the significant air pollution that would be caused by the Grayson Project, and is therefore unlawful.

What the DEIR calls "New Source Review Offsets" are Emission Reduction Credits required by the Federal Clean Air Act as part of the Act's tools to edge the South Coast Air Basin toward meeting the health-based National Ambient Air Quality Standards. Glendale sits in an area that is unique in the United States: this area is the only one that has *never* met *any* of the Act's Ozone[51] standards. The first Ozone standard became effective in 1979. This region has not met that standard. Subsequent to the first standard, new standards were established in 1993, 1997, 2008, and 2015. None of those standards have been met. Failure to meet this standard has real and significant environmental and health impacts, and the Grayson Project's significant air pollution emission cause Ozone. Ozone is formed when NOx and VOC emissions combine with heat and sunlight. Ozone causes significant health problems from burning eyes to asthma and heart attack.

[50] DEIR 4.3.34
[51] Ozone is also known as "smog."



959-13

Because the South Coast Air Basin's Ozone is so bad, and because the environmental health impacts of ozone are so serve, the significance thresholds for NOx and VOCs are low. Those thresholds reflect the importance of facilities doing everything possible to reduce emissions at the source. In the context of CEQA, the thresholds reflect the requirement that facilities take seriously the environmental impacts of NOx and VOCs and identify and use all feasible mitigations and alternatives to avoid emitting them. Simply declaring that the NOx and VOC significance thresholds are not exceeded because Grayson will have Emission Reduction Credits reduces environmental protections required by CEQA to an empty exercise since all new sources of NOx and VOCs in the South Coast Air Basin require Emission Reduction Credits. Because overall emissions in the Los Angeles Basin must be reduced in order to meet these health-based standards, supply of these Emission Reduction Credits is extremely limited, and, even if available, come at a very high price. Although a small "reserve bank" of offsets is available for "essential public services," the Project would not be eligible to tap this reserve because market sales of surplus energy do not qualify as an essential public service.

b. The greenhouse gas emissions are significant

959-14

The DEIR uses an approach to analyzing the significance of greenhouse gases (GHG) that is similar to the improper approach used for analyzing air pollution. In this section, the DEIR calculates the total GHG emission from the Grayson Project as 476,406 Metric Tons per year

(MT/year) of CO2e[52] and the net increase after subtracting the current emissions from Grayson as 415,832 MT/year of CO2e.[53] This amount of GHG emissions is significant both because of its impact on the environment and because it clearly exceeds the significance threshold of 10,000 MT/year. Since the Grayson Project's GHG emissions exceed the significance threshold, GWP is obligated to consider all feasible mitigation measures and alternatives. If, after all feasible mitigation is adopted, Grayson's GHG emissions still exceed the threshold then GWP may do a statement of overriding considerations. What GWP cannot do, however, is simply assert that the emissions are not significant because Grayson will be part of California's cap-and-trade program. 959-14

First, the increase in GHGs caused by the Grayson Project are significant in terms of their environmental impacts. The climate crisis is real. "Scientists have high confidence that global temperatures will continue to rise for decades to come, largely due to greenhouse gases produced by human activities."[54] And we are already seeing the effects of climate change here. For example, in the Southwest "increased heat, drought and insect outbreaks, all linked to climate change, have increased wildfires. Declining water supplies, reduced agricultural yields, health impacts in cities due to heat, and flooding and erosion in coastal areas are additional concerns."[55]

The Grayson Project will *add* 415,832 MT/year of CO2e of GHG emissions. The United States Environmental Protection Agency has a tool that makes GHG emissions, which can be a little abstract, a little more concrete by giving examples of what they mean in every day terms such as how many cars driven, or how many miles by a passenger car, or how many barrels of oil consumed, or how much coal burned, or what it would take to sequester those emissions. For context, here are EPA's estimates for some equivalences of the added emissions from the Grayson Project:

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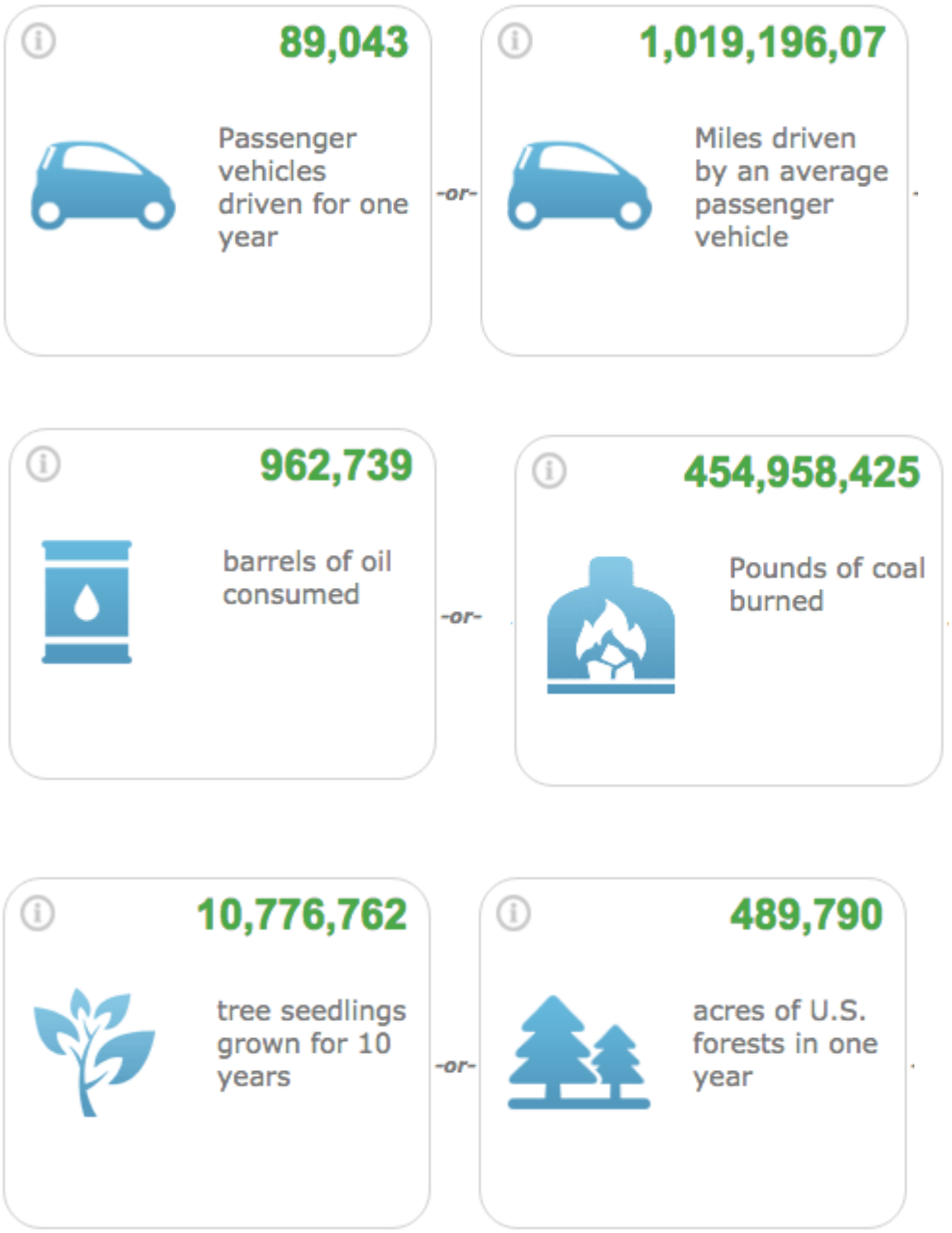
[52] DEIR 4.5.7.
[53] DEIR 4.5.7.
[54] NASA, Global Climate Change: Vital Signs of the Planet (https://climate.nasa.gov/effects/)
[55] Ibid.

959-14



The actual emissions from the Grayson Project are significant.

In addition to the real world significance, the Grayson Project exceeds the significance threshold of 10,000 MT/year of CO2e. The DEIR explains:

> As shown in Table 4-37, the net increase of GHG emissions from the operation of the Project exceeds the significance threshold of 10,000 metric tons per year. The GHG emissions

> exceedance is solely contributed from operating the proposed combustion turbines and transformers.[56]

Despite the clarity of this statement, the DEIR then finds that the GHG emissions from the Grayson Project are "Less than significant" before mitigation.[57] This counterintuitive claim is based on the wrongful assertion that because the Grayson Project "is required to comply with the State cap and trade program" the GHG emissions are not significant. This is wrong. Participation in the cap and trade program does not reduce emissions from the Project, rather is simply requires a Project to buy carbon permits. Its purpose is to put a price on carbon to encourage people to figure out ways to reduce GHGs; the cap and trade program itself does not reduce emissions at a project.[58] Here, just as with its air pollution, GWP is required to explore mitigation and alternatives that would reduce or eliminate GHG emissions prior to approving the Grayson Project. If the GHG emissions cannot be reduced to a level below the significance threshold, then Glendale may disclose that fact and do a statement of overriding consideration. What Glendale cannot do is ignore its obligations under CEQA. 959-14

c. The risks to the power plant from an earthquake are significant

The DEIR identified a "moderate potential for surface rupture from the Verdugo fault and other nearby active faults during the design life of the proposed development."[59] Further, it is "expected" that strong ground shaking will occur at the Grayson Project site."[60] And, the Grayson Project site is in a known "liquefaction" zone.[61] Put another way, there is a significant chance that an active earthquake fault will cause earthquake near the Grayson site and when that happens, the soil can experience significant settlement—"approximately 11 inches."[62] 959-15

The DEIR establishes that the risk to the project requires mitigation because it is in an established liquefaction zone, writing:

> According to the State of California Seismic Hazards Zones – Burbank Quadrangle Map (released March 25, 1999), the Project area is located within a liquefaction zone, which is defined as an area where historic occurrence of liquefaction or where local geological,

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[56] DEIR 4.5.7.
[57] DEIR 4.5.7.
[58] Because State law requires that overall carbon emissions be reduced, the "cap" part of cap and trade will reduce the quantity of these permits available for purchase over time. The price of these permits will increase accordingly and add more costs to the Grayson Project over time.
[59] DEIR 4.4.6.
[60] DEIR 4.4.7.
[61] "Liquefaction occurs when loose, unconsolidated, water-laden soils are subject to ground shaking, causing the soils to lose cohesion." DEIR 4.4.7.
[62] DEIR 4.4.8.

geotechnical, and groundwater conditions indicate a potential for permanent ground displacements *such that mitigation as defined in Public Resources Code Section 2693(c) would be required*.

959-15

Being in a mapped liquefaction zone establishes that the risk of liquefaction is significant. As such, as described above, the DEIR must identify the impact as significant and adopt all feasible mitigation or alternatives to reduce that impact below significance. Further, GWP may not simply assert that "the results of additional, forthcoming geotechnical assessments within the Project Area will be utilized to further evaluate potential engineering impacts and to design possible mitigation measures as they pertain to liquefiable soils."[63] CEQA does not allow the DEIR to shift mitigation identification and adoption to after approval as attempted here.[64]

IV. Conclusion

959-16

Glendale Water and Power's Draft Environmental Impact Report does not meet the clear informational requirements of the California Environmental Quality Act. It is clear that the Grayson Project is significantly larger than what is needed to meet Glendale's energy needs. The DEIR fails both to disclose the fact that the Grayson Project is oversized and fails to clearly establish the environmental impacts of this massive project. In addition, the massive size of the project resulted in flawed construction and analysis of alternatives to the Project. The alternatives analysis that was constructed is legally inadequate because it fails to inform meaningful consideration of feasible alternatives to the proposed project. Finally, the DEIR improperly hides the significant impacts of air pollution, greenhouse gas emissions, and earthquake risk and as a result fails to properly consider mitigation of and alternatives to the Grayson Project. Left uncorrected, each of these defects would render a Final Environmental Impact Report unlawful.

Respectfully submitted,

Angela Johnson Meszaros
Staff Attorney

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[63] DEIR 4.4.7 – 4.4.8.

FOOTNOTE 2

What's a Watt?

A watt is a measure of electricity. If you have 10, 100-watt bulbs all on at the same time, the "demand" or instantaneous measure of the power required for the job, is 1,000 watts, also called 1 kilowatt, or kW. If you keep them lit for one full hour, you have used 1,000 watt-hours of electricity, also called a kilowatt-hour or kWh. The typical American home uses about 840 kWh per month.

Megawatt: One megawatt equals one million watts, or 1,000 kilowatts, roughly enough electricity for the instantaneous demand of 750 homes at once. That number fluctuates (some say one megawatt is enough for 1,000 homes) because electrical demand changes based on the season, the time of day, and other factors.

Gigawatt: You guessed it, one billion watts.

Voltage: Hard to describe, but just as it takes pressure to move water through a pipe, it takes voltage to move electricity across a wire. Transmission lines usually carry power at 500, 230 or 115 kV. It is "stepped down" into lower voltage (69 kV and lower) by transformers at substations and along distribution lines for final delivery to homes and businesses. It comes into your house at 220 volts, and most of your household plugs carry 110 volts.

Capacity: How much electricity an electrical facility can carry or generate. Usually applied to generators, transmission lines, substation equipment and distribution lines.

Energy vs Capacity: If you're filling up a bucket with water from a garden hose, the amount of water moving through the hose is the "energy" or wattage, and the water pressure inside the hose is the voltage. The size of the hose is the capacity.

The Electrical Grid: Continuing the water analogy, envision the electrical grid as a big pressurized water system with hundreds of pumps (generators) pumping water into the system through long pipes (transmission lines), and literally millions of customers sucking water out through smaller straws (utility distribution systems). There are hundreds of places (substations) where valves and adapters (switches and transformers) are used to break the large volumes of water down into smaller units under less pressure for delivery through the straws. The ISO's job is to make sure that in the high-pressure system, the water pressure (voltage) and the RPMs of all the pumps (frequency) remain constant, even though inflow and outflow (measured in wattage) are both changing minute by minute.

Frequency: Much like radio signals, electric generators can be "tuned" to produce power that vibrates at different frequencies. In the United States, virtually all electricity is generated and transmitted at 60-hertz or 60 cycles. Motors and other electrical equipment in the U.S. are calibrated to run at 60Hz. As the frequency fluctuates, it can damage all manner of electrical equipment. Frequency can be affected by a variety of factors and must be monitored closely to make sure it doesn't fluctuate.

Load: The load is the energy use; the ISO refers to utilities like PG&E as "load-serving entities" because that's what they do, they serve a load. Load is frequently confused with demand, which is actually how much power the load requires.

Demand: The number of kilowatts or megawatts delivered to the load at a given instant.

Market Participant (MP): Any entity that buys, sells, trades, transmits or distributes electricity in the California ISO control area. This includes utilities, generating companies, transmission owners, energy-trading companies and Scheduling Coordinators.

Scheduling Coordinator (SC): Entities that buy or sell power through the California ISO have to do so through a Scheduling Coordinator. The SC is specifically authorized by the ISO to handle this type of transaction. SCs may be a subsidiary of the company they represent, or hired as agents to represent the company.

Investor Owned Utility (IOU): This title usually applies to one or all of the big three utilities in California: Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). It refers to the fact that these are private companies, owned by stockholders, as opposed to municipal utilities, like Los Angeles Department of Water and Power (LADWP).

FOOTNOTE 3

ALL TOPICS

	Glendale city, California
Households, 2011-2015	71,498

QuickFacts
Glendale city, California

QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

PEOPLE	
Population	
Population estimates, July 1, 2016, (V2016)	200,831
Population estimates base, April 1, 2010, (V2016)	191,685
Population, percent change - April 1, 2010 (estimates base) to July 1, 2016, (V2016)	4.8%
Population, Census, April 1, 2010	191,719
Age and Sex	
Persons under 5 years, percent, July 1, 2016, (V2016)	X
Persons under 5 years, percent, April 1, 2010	4.8%
Persons under 18 years, percent, July 1, 2016, (V2016)	X
Persons under 18 years, percent, April 1, 2010	18.6%
Persons 65 years and over, percent, July 1, 2016, (V2016)	X
Persons 65 years and over, percent, April 1, 2010	15.6%
Female persons, percent, July 1, 2016, (V2016)	X
Female persons, percent, April 1, 2010	52.3%
Race and Hispanic Origin	
White alone, percent, July 1, 2016, (V2016) (a)	X
Black or African American alone, percent, July 1, 2016, (V2016) (a)	X
American Indian and Alaska Native alone, percent, July 1, 2016, (V2016) (a)	X
Asian alone, percent, July 1, 2016, (V2016) (a)	X
Native Hawaiian and Other Pacific Islander alone, percent, July 1, 2016, (V2016) (a)	X
Two or More Races, percent, July 1, 2016, (V2016)	X
Hispanic or Latino, percent, July 1, 2016, (V2016) (b)	X
White alone, not Hispanic or Latino, percent, July 1, 2016, (V2016)	X
Population Characteristics	
Veterans, 2011-2015	4,883
Foreign born persons, percent, 2011-2015	54.4%
Housing	
Housing units, July 1, 2016, (V2016)	X
Housing units, April 1, 2010	76,269
Owner-occupied housing unit rate, 2011-2015	35.3%
Median value of owner-occupied housing units, 2011-2015	$619,200
Median selected monthly owner costs -with a mortgage, 2011-2015	$2,702
Median selected monthly owner costs -without a mortgage, 2011-2015	$587
Median gross rent, 2011-2015	$1,296
Building permits, 2016	X
Families & Living Arrangements	
Households, 2011-2015	**71,498**
Persons per household, 2011-2015	2.73
Living in same house 1 year ago, percent of persons age 1 year+, 2011-2015	87.6%
Language other than English spoken at home, percent of persons age 5 years+, 2011-2015	69.7%
Education	
High school graduate or higher, percent of persons age 25 years+, 2011-2015	84.4%
Bachelor's degree or higher, percent of persons age 25 years+, 2011-2015	37.9%
Health	
With a disability, under age 65 years, percent, 2011-2015	6.6%
Persons without health insurance, under age 65 years, percent	▲ 18.5%

ALL TOPICS

Households, 2011-2015

Economy	Glendale city, California	
In civilian labor force, total, percent of population age 16 years+, 2011-2015	61.8%	
In civilian labor force, female, percent of population age 16 years+, 2011-2015	56.3%	71,498
Total accommodation and food services sales, 2012 ($1,000) (c)	400,499	
Total health care and social assistance receipts/revenue, 2012 ($1,000) (c)	1,638,525	
Total manufacturers shipments, 2012 ($1,000) (c)	842,272	
Total merchant wholesaler sales, 2012 ($1,000) (c)	1,386,584	
Total retail sales, 2012 ($1,000) (c)	3,138,231	
Total retail sales per capita, 2012 (c)	$16,137	
Transportation		
Mean travel time to work (minutes), workers age 16 years+, 2011-2015	27.1	
Income & Poverty		
Median household income (in 2015 dollars), 2011-2015	$52,574	
Per capita income in past 12 months (in 2015 dollars), 2011-2015	$29,869	
Persons in poverty, percent	▲ 14.6%	

BUSINESSES

Businesses	
Total employer establishments, 2015	X
Total employment, 2015	X
Total annual payroll, 2015 ($1,000)	X
Total employment, percent change, 2014-2015	X
Total nonemployer establishments, 2015	X
All firms, 2012	29,153
Men-owned firms, 2012	16,696
Women-owned firms, 2012	9,018
Minority-owned firms, 2012	8,293
Nonminority-owned firms, 2012	19,640
Veteran-owned firms, 2012	1,928
Nonveteran-owned firms, 2012	26,016

GEOGRAPHY

Geography	
Population per square mile, 2010	6,295.6
Land area in square miles, 2010	30.45
FIPS Code	0630000

FOOTNOTE 5

glendale
california

CITY OF GLENDALE, CALIFORNIA
REPORT TO THE:

Joint ☐ City Council ☒ Housing Authority ☐ Successor Agency ☐ Oversight Board ☐

June 2, 2015

AGENDA ITEM

Report: Integrated Resource Planning Report

1. Resolution directing staff to proceed with design, engineering, environmental review, and evaluation of financing options for the 250 MW option to repower the Grayson Power Plant as identified in the Integrated Resource Planning Report

COUNCIL ACTION

Public Hearing ☐ Ordinance ☐ Consent Calendar ☐ Action Item ☒ Report Only ☐

Approved for June 2, 2015 calendar

ADMINSTRATIVE ACTION

	Signature
Submitted by: Stephen M. Zurn, General Manager - GWP	
Reviewed by: Ramon Z. Abueg, Chief Assistant General Manager	
Prepared by: Lon L. Peters, Integrated Resources Planning Administrator	
Approved by: Scott Ochoa, City Manager	
Reviewed by: Yasmin K. Beers, Assistant City Manager	
Michael J. Garcia, City Attorney	by
Robert P. Elliot, Director of Finance	Robert Elliot

RV

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RECOMMENDATION

It is recommended that the City Council adopt a Resolution directing staff to proceed with design, engineering and environmental analyses, and evaluation of financing options for repowering the Grayson Power Plant.

BACKGROUND/ANALYSIS

GWP faces several significant decisions over the next few years in order to (a) maintain reliable service, (b) comply with state regulations regarding renewable energy supplies and greenhouse-gas emissions, and (c) keep rates affordable to ratepayers in the City. Decisions regarding new generation resources, renewable or fossil-fueled, require the analysis and integration of all generating and transmission resources, known and forecasted load growth in the city, demand-side conservation programs, regulatory compliance, and measures to mitigate the impact on the ratepayers.

The City's Grayson Power Plant is experiencing an increasing frequency in unplanned and forced outages. These outages threaten local reliability and prevent the generation of renewable energy from landfill gas from Scholl Canyon. GWP has one major interconnection through the Air Way Substation to import energy from remote generation. These imports rely on available transmission, but the transmission grid has contractual and physical limitations to bring in all the energy that is necessary to provide reliable service to Glendale. Additionally, GWP has outside generation sources that are planned for retirement or contract termination.

In August 2014, City Council approved staff's recommendation to retain Pace Global as the consultant to develop a complete Integrated Resource Plan (IRP) that addresses all of these issues and guides future decisions. City Council also authorized retention of Stantec (then Processes Unlimited) as Owner's Engineer (OE) to undertake significant design and engineering studies, in order to ensure that, if the City Council elects to proceed with the repowering of the Grayson Power Plant, the City can meet state environmental requirements associated with construction of a large power project, prepare for demolition, and ensure proper and safe deconstruction, construction and commissioning of a new power plant. The results of these studies were used to prepare the IRP analyses, which included:

1. Screening and evaluation of Grayson repower options;
2. Screening and evaluation of new interconnection options;
3. Assessment of renewable generation technologies; and
4. Evaluation of generation and transmission portfolios.

The IRP covers the period from 2016 through 2035. During this period, GWP will need to:

- meet state Renewable Portfolio Standards (RPS)
- manage carbon allowances and carbon market exposure
- implement energy efficiency and demand side management programs
- acquire energy storage if cost effective,
- manage an overall short position on an annual energy basis
- manage risks in various markets
- develop plans for replacing existing coal-fired resource supplies at the Intermountain Power Project (IPP) in Utah and the San Juan Project in New Mexico
- consider replacing its aging power plant (Grayson) inside the City limits and
- make best use of existing landfill gas (LFG) supplies in the City.

Additionally, GWP expects changes in the requirements (i.e., inadvertent or imbalance bandwidths) for managing internal and external generation to meet retail loads within the Balancing Area of the LADWP.

The existing Grayson Power Plant units (except Unit No. 9) are not reliable. The forced outage rates are so high that the capacity is not necessarily available when needed, such as during a major event that separates the Glendale electric system from its interconnection with LADWP or during a heat storm. As the units continue to degrade, GWP will need to purchase additional transmission capacity to bring energy into Glendale from outside resources to meet retail load. Transmission capacity for such imports may not always be available, which also risks local reliability. The boiler units that burn the landfill gas to produce energy have proven to be unreliable, which has resulted in flaring the gas at Scholl Canyon. This causes GWP to lose renewable energy credits (RECs), and increases energy costs by the need to purchase replacement energy from spot markets.

The IRP constructs a long-term forecast of GWP's load using econometric techniques. The IRP then takes into consideration GWP's forecasted load profile, operating reserve requirements and limits on import capacity, as well as regulatory requirements affecting GWP's resource needs, such as renewable portfolio and greenhouse gas mandates, reliability requirements, and control area compliance obligations. Additionally, the IRP analyzes various options for the replacement of the San Juan and Intermountain Power Project coal-fired generation plants and evaluates conservation programs, time-of-use rates, potential for distributed generation inside Glendale and energy storage.

The IRP evaluates various resource portfolio options to meet GWP's forecasted load. These options including a "run to fail" option at Grayson and various configurations for repowering the Grayson Power Plant (roughly 150MW, 200MW and 250MW of new generating capacity). All the options meet the 33% Renewable Portfolio Standards by integrating renewable resources from a portfolio of wind, solar and geothermal resources. They also include the continuous operation of Unit #9 and relocating the generation that burns landfill gas to Scholl Canyon. The IRP tests the robustness of various resource portfolios against future market and regulatory scenarios. Each resource portfolio was evaluated in terms of cost per MWh, net present value of the entire system, compliance with regulatory requirements, and impacts on local reliability.

The Table below summarizes the results of the IRP analyses:

Portfolios Study Period: 2016-35 All portfolios meet 33% RPS	**Cost**	**Risk/ Rate Stability**		**Reliability**		**Environmental Stewardship**	**Flexibility/ Financial Stability**
	Reference Case Levelized NPV* ($/MWh)	Worst Case Cost across Scenarios ($/MWh)	Reliance on market (Net Sales as a % of Total Portfolio Costs- 2020)	Total MWh of Lost Load over 10-year Period	Range Value of Lost Load (millions of 2013$)	Total CO_2 Emissions for owned resources plus purchases 2019-2035 average (000s tons)	Total Capital Investment at Grayson and LFG (millions of $)
Run to Fail	103.9	115.5	-7%	2019: 569 2027: 5,962	2019: 0.75-2.6 2027: 7.9-27.0	338.9	8.5
150B/ wind/ solar/ geo	95.3	104.8	0%	2019: 186 2027: 55	2019: 0.25-0.84 2027: 0.07-0.25	407.8	201.4

200B/ wind/ solar/ geo	95.7	105.4	1%	2019: 55	2019: 0.07-0.25	428.8	263.1
200C/ wind/ solar/ geo	95.1	102.5	14%	2019: 45	2019: 0.05-0.20	514.6	300.1
250D/ wind/ solar/ geo	94.0	100.2	27%	2019: 28	2019: 0.04-0.13	603.0	337.1

With respect to the future of the Grayson Power Plant, the analyses show that the "Run to Fail" option has the highest cost at $103.90/MWh (net present value). The "250 D" Grayson repowering option has the highest initial capital investment but yields the lowest cost at $94.00/MWh (net present value). All options will require bond financing to spread the capital cost over the life of the new assets.

The "Run to Fail" and "150 B" options require the least capital investment but also fail to meet the North American Reliability Corporation (NERC) reliability requirements.

The "200 B" and "200 C" options meet all the criteria of Risk/Rate Stability, NERC Reliability, and Financial Stability.

The capital investment to repower with the 200 MW and 250 MW options ranges from $200 million to $340 million but the Levelized Net Present Value cost is lowest with the 250 MW option. These options also show increases in total carbon (CO2) emissions compared with the "Run to Fail" option, viewed only from the Glendale perspective. However, new generation units at Grayson will be more efficient and therefore will displace higher CO2 emitting units in the region, thus helping reduce greenhouse gases more broadly.

The 250 MW option provides the highest flexibility and reliability. It will have the capacity to provide energy to the entire city of Glendale load to keep the lights on during a system wide emergency and if disconnected from LADWP under almost all conditions.

Based upon the results of the IRP Study, GWP recommends against the "Run to Fail" option for the Grayson Power Plant. GWP recommends that the City Council direct GWP to proceed with the design, engineering, environmental analysis, and evaluation of financing options for the 250 MW option (identified as "250D" in the IRP) to repower the Grayson Power Plant.

The estimated project timeline to complete the various tasks required for the repowering of the Grayson Power Plant as recommended is 5-6 years. The project timeline and decision point schedule are attached as Exhibit A.

FISCAL IMPACT

Pace Global/Siemens will complete the IRP by late June for $329,450 as previously authorized by City Council. Funds are currently budgeted in the current FY2014-15 in project 11681 (Fund No. 552, Org. No. 921). Additionally, Stantec, the Owner's Engineer, has completed the preliminary engineering phase of the IRP for less than $250,000. Funds for this work are currently budgeted in the current FY2014-15 in project 13748 (Fund No. 553, Org. No. 921). City Council previously authorized this contract with Stantec for $6.85 million, plus a contingency of $685,000 (ten percent), for a total of $7.535 million, to perform the engineering design and analysis. Funds for the remaining portion of this contract were included as part of the proposed FY2015-16 budget. Once the IRP is complete, the estimated cost of Phase V in the Stantec scope of work is $1.25 million (included in the $7.535M). This Phase covers (1) preliminary engineering sufficient for

permitting and environmental studies, (2) preparation of an Environmental Impact Report (EIR) required under the California Environmental Quality Act (CEQA), and (3) preparation of permit application packages for state, regional and local permitting agencies. The final cost of repowering Grayson will not be determined until the detailed design and regulatory analyses are finalized and ultimately would require the sale of bonds.

ALTERNATIVES

Alternative 1: Direct staff to proceed with design, engineering, environmental review, and evaluation of financing options for the 250 MW option to repower the Grayson Power Plant.

Alternative 2: Direct staff to proceed with design, engineering, environmental review, and evaluation of financing options for the 200 MW option to repower the Grayson Power Plant.

Alternative 3: Direct staff to run the power plant to failure and submit analyses on the impact on cost, reliability and regulatory compliance to meet system load requirements.

Alternative 4: Council may adopt any alternative not recommended by staff.

CAMPAIGN DISCLOSURE

Not applicable

EXHIBIT(S)

Exhibit A: Project Timeline/Decision Point Schedule

Exhibit B: Presentation by Pace Global on the Final Draft – Integrated Resource Planning Report

RESOLUTION NO. _____

A RESOLUTION OF THE COUNCIL OF THE CITY OF GLENDALE, CALIFORNIA DIRECTING GLENDALE WATER & POWER TO PROCEED WITH THE DESIGN, ENGINEERING, ENVIRONMENTAL REVIEW AND EVALUATION OF FINANCING OPTIONS FOR A PROPOSED 250 MEGAWATT REPOWERING OF THE GRAYSON POWER PLANT IN THE CITY OF GLENDALE

WHEREAS, Glendale Water & Power ("GWP") faces several significant decisions over the next few years in order to maintain reliable electric service, to comply with state regulations regarding renewable energy supplies and greenhouse gas emissions, and to keep utility rates affordable for GWP customers; and

WHEREAS, the City of Glendale's Grayson Power Plant ("Grayson") is experiencing, with increasing frequency, unplanned outages which threaten local reliability and prevent the generation of renewable energy from landfill gas from Scholl Canyon; and

WHEREAS, GWP is facing significant contractual and physical limitations on its ability to import sufficient outside generation sources necessary to supply reliable service to Glendale including transmission constraints and outside generation resources that are planned for retirement or contract termination; and

WHEREAS, pursuant to the City Council's August 19, 2014 direction, the City retained Pace Global/ Siemens Industry, Inc. ("Pace") to develop a complete Integrated Resource Plan ("IRP") covering the period from 2016 through 2035, to address GWP's energy objectives and needs and guide future decisions; and

WHEREAS, the IRP analysis constructs a long-term forecast of GWP's load using econometric techniques, and includes (i) the screening and evaluation of Grayson repower options; (ii) the screening and evaluation of new interconnection options; (iii) the assessment of renewable generation technologies and (iv) the evaluation of generation and transmission portfolios, while taking into account GWP's goals of reliability, affordability, and sustainability; and

WHEREAS, the IRP evaluates various resource portfolio options to meet GWP's forecasted load, and tests the robustness of each of the resource portfolio options against future market and regulatory scenarios, in terms of cost per megawatt-hour, net present value of the entire system, compliance with regulatory requirements, and impacts on local reliability; and

WHEREAS, based upon the IRP analysis, and as further described in the June 2, 2015 Report of the General Manager and the June 2, 2015 IRP presentation by Pace, the 250 MW repowering option for Grayson (identified as option "250D" in the IRP) provides the City of Glendale highest flexibility and greatest reliability and will have the capacity to provide energy to the entire City of Glendale electric load in order to keep the lights on during a system wide emergency and during periods of disconnection from Los Angeles Department of Water & Power under almost all conditions.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF GLENDALE:

That, having considered GWP and Pace's June 2, 2015 report and presentation regarding the IRP, and public comments regarding the IRP, the City Council hereby directs the General Manager of Glendale Water & Power to proceed with the design, engineering, environmental review,

///

///

and evaluation of financing options for the proposed 250 MW option for repowering the Grayson Power Plant, identified as option "250D" in the Pace Integrated Resource Plan analysis.

Adopted this _____ day of _____, 2015

_____
Mayor

ATTEST:

_____
City Clerk

STATE OF CALIFORNIA)
) SS
COUNTY OF LOS ANGELES)

I, Ardashes Kassakhian, City Clerk of the City of Glendale, certify that the foregoing Resolution No. _____ was adopted by the Council of the City of Glendale, California, at a regular meeting held on the _____ day of _____, 2015, by the following vote:

Ayes:

Noes:

Absent:

Abstain:

_____
City Clerk

APPROVED AS TO FORM

Principal Assistant City Attorney
Date May 28, 2015

Exhibit A

PROJECT TIMELINE AND DECISION POINT SCHEDULE

Develop and Complete Integrated Resource Plan	June 2015
• Decision Point: Determine ultimate configuration of Grayson Power Plant	June 2015
Engineering for permitting and environmental assessments	July 2015 – Dec. 2016
RFP process and selection of Bond Counsel and Financial Services Advisor	January 2016
RFP for major capital assets	June 2016
RFQ for EPC contractors	September 2016
All permits in place	December 2016
• Decision Point: Proceed with Debt Issuance and Retention of EPC Contractor for Construction	December 2016
RFP for EPC contractor; Retain EPC	June 2017
Demolition	September 2017
Construction	2018-2020
New plant in operation	2018 (Scholl) 2020 (Grayson)

EXHIBIT B

SIEMENS

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2015 IRP DRAFT Findings

Glendale Water and Power Commission

May 4, 2015

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Answers for infrastructure and cities.

Motivation for the IRP Project

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- Grayson: aging local power plant, increasing forced outages, increasing cost to maintain, inefficient combustion of landfill gas (LFG)
- RPS compliance: additional renewables necessary by late 2020s under current law
- GHG compliance: need to prepare for end of free allowances
- Contract expirations or resource shut-downs: San Juan, renewables, IPP
- Renewable integration: renewables require complementary generation
- Operations in LA's Balancing Area: expected to become more costly, and self-supply needs to be evaluated
- Storage options: needed for integrating renewables and self-supply of capacity required for operation in LA's Balancing Area
- Rate design issues: using the new Smart Meters

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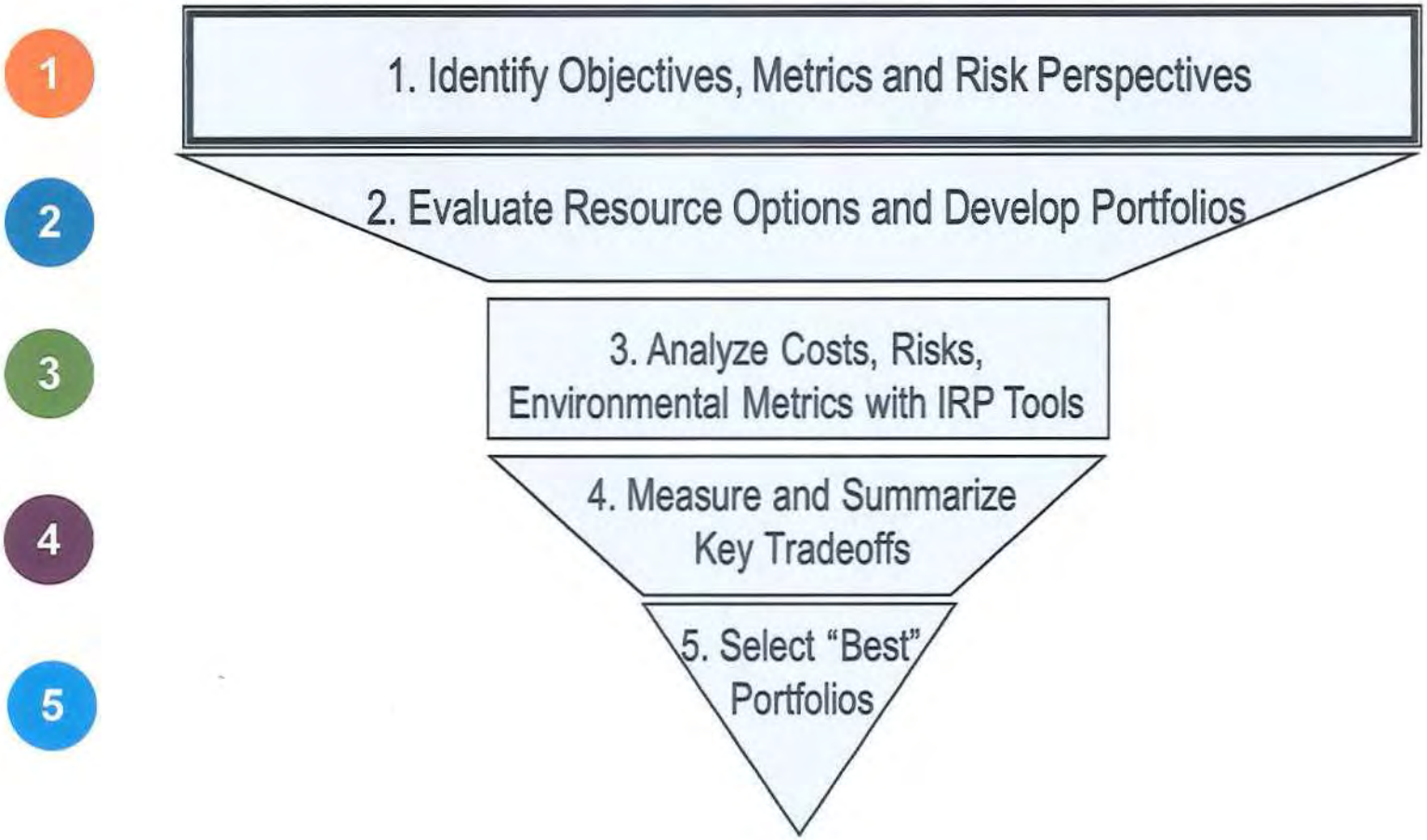
Overview of IRP Process



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1

Objectives and Metrics

Objective	Metric
Minimize Cost	Levelized NPV ($/MWh) generation portfolio costs
Improve Rate Stability/ Manage Risks to Ratepayers	Range of $/MWh levelized costs across scenarios
	Reliance on market transactions (% of total costs)
Improve Reliability	Frequency and total MWh of loss of load events
Enhance Environmental Stewardship	CO_2 emissions; Renewable %
Support Financial Stability	Total invested capital

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2

Major Elements of IRP for GWP

Resource Planning Issues	Approach
Grayson Re-Powering	
RPS Compliance – Current and Potential Future Laws	
Shift from Coal Power – San Juan and IPP	Quantitative Screening of Options for Portfolios
Energy Storage	
LFG (Scholl Canyon)	
Energy Efficiency and Load Reductions (TOU Rates)	Load Forecast w/ Study of Time-of-Use (TOU) Rates
Carbon and GHG Legislation	
Transmission Options	Portfolio Modeling
Energy Market Structure and Ancillary Services	
Distributed Generation and Solar Technology Advances	Customized Study

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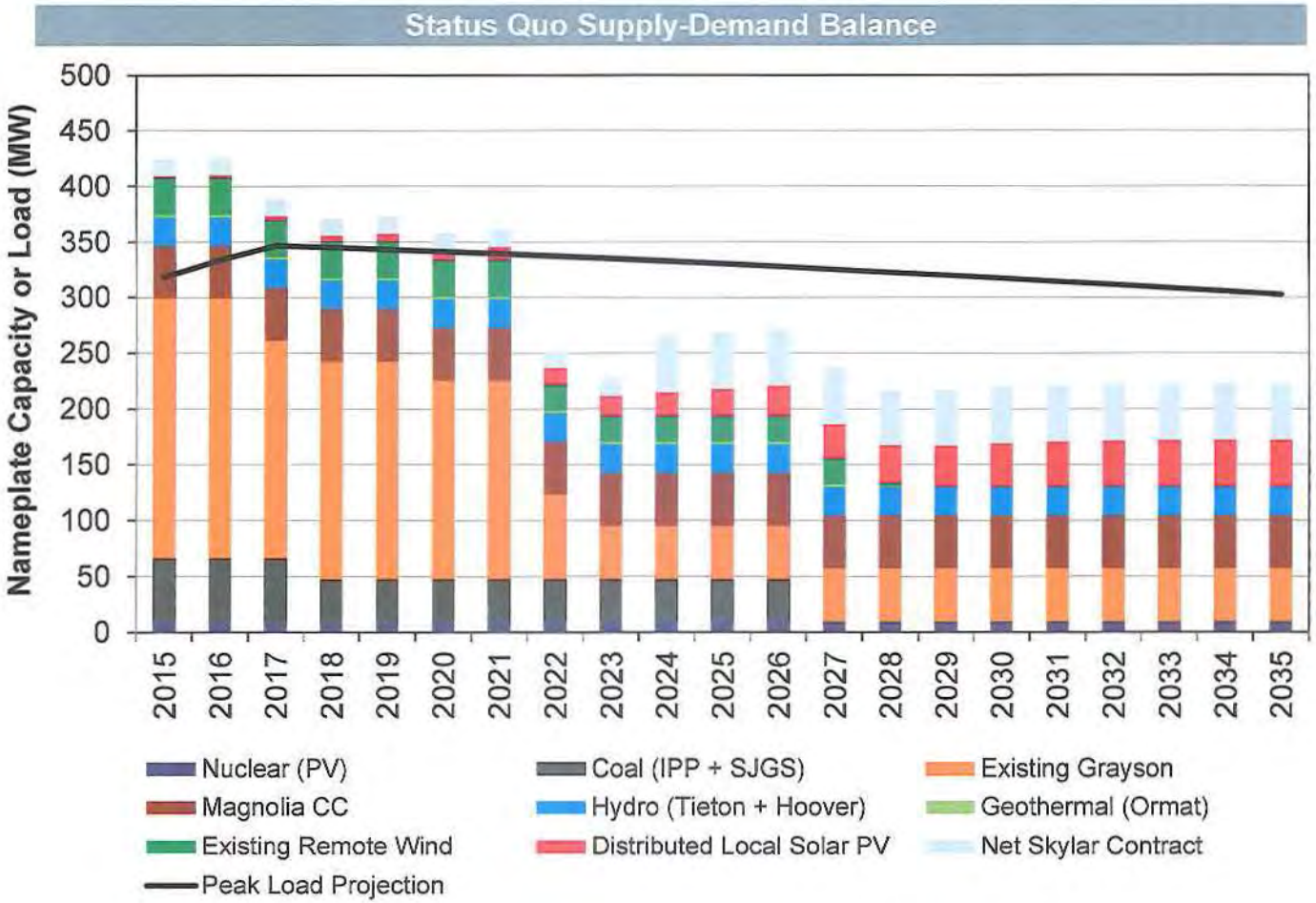
2

Existing Portfolio is Likely to Develop Capacity Shortage Soon



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Screening for Each Major IRP Issue

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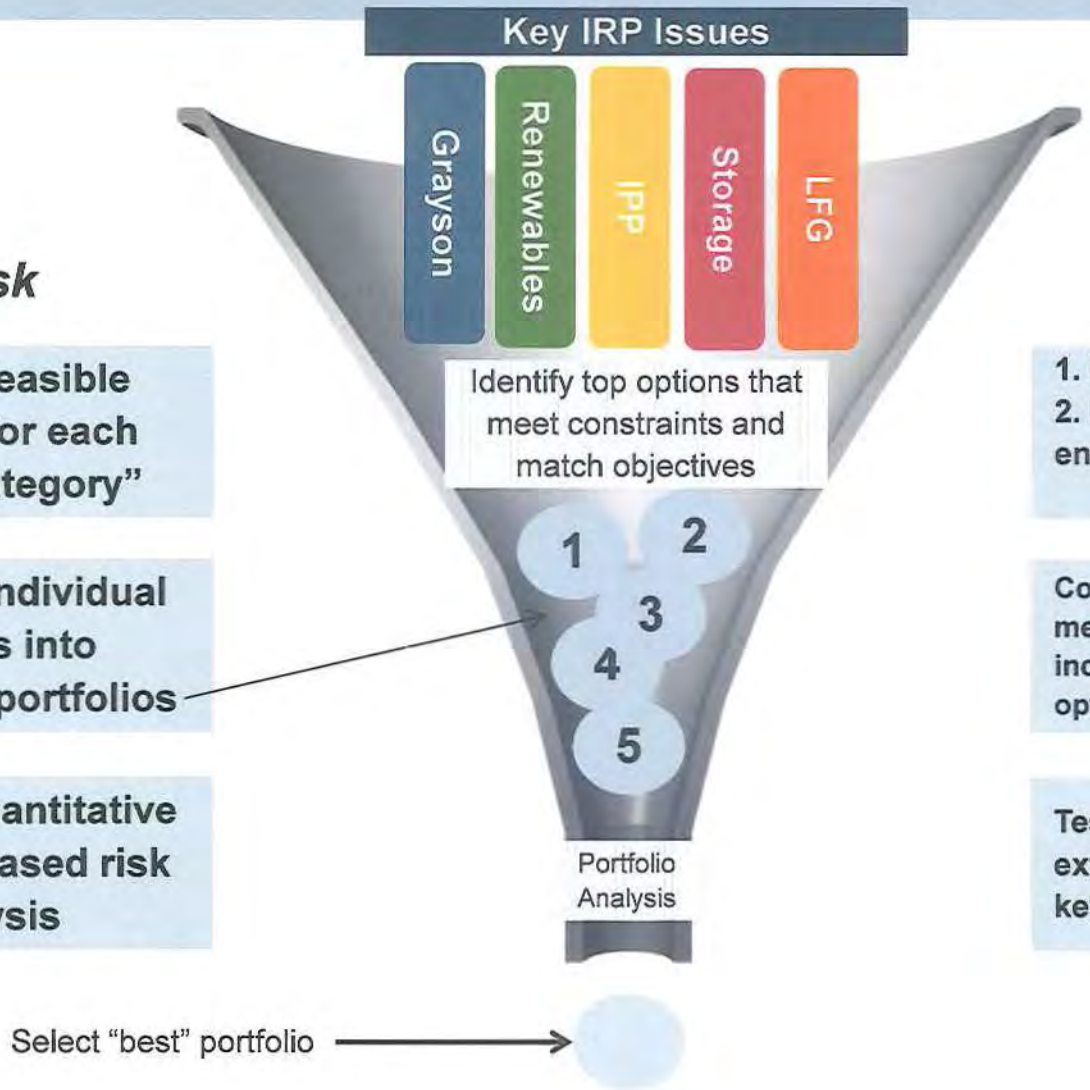
Task

Screen feasible options for each "issue category"

Combine individual options into integrated portfolios

Perform quantitative scenario-based risk analysis



Approach

1. Meet planning constraints;
2. Rank by cost and environmental performance (Excel and Aurora)

Construct portfolio options that meet constraints and incorporate various strategy options

Test each portfolio against external market risks and all key metrics

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Screening Performed for Major Issue Categories

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Grayson

- Developed 9 configurations; narrowed to 4 leading options; Unit 9 kept in all analyses

Renewables

- Evaluated costs of remote renewable options; narrowed options to combinations of intermittent wind & solar, and baseload geothermal

IPP

- Tested new combined cycle combustion turbine (CC) and peaker options at IPP compared with walking away; narrowed to CC

Storage

- Screened out grid-scale and behind-the-meter storage; *local option for regulation services* *still under study*

LFG

- Developed separate from Grayson; Identified three distinct turbine and engine options at Scholl Canyon Landfill

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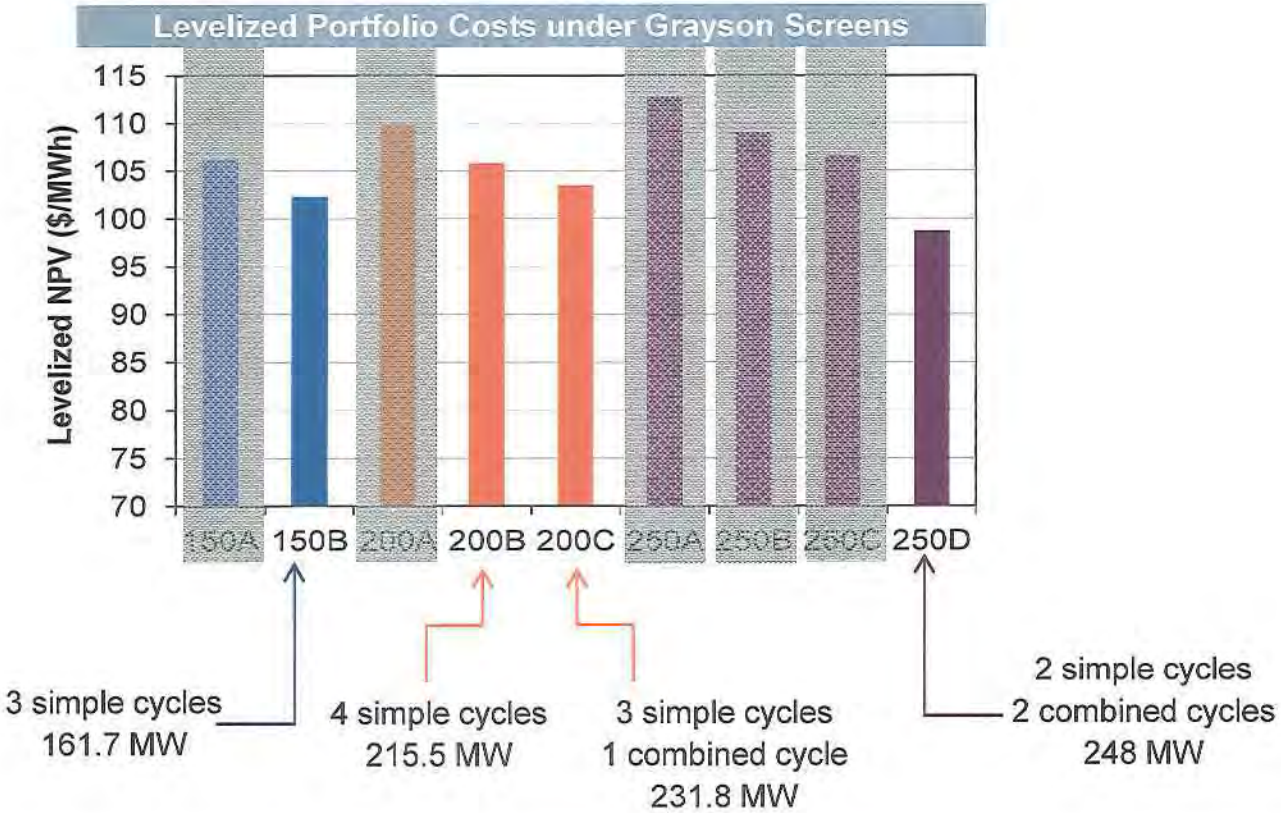
Grayson Screening

- Initial technology screen performed by Stantec
- Wartsila options costly due to inflexibility, so eliminated
- Narrowed to four options with combinations of LM6000 simple cycles and combined cycles



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Grayson Screening – Incremental Transmission

- The Grayson screening analysis included additional transmission capacity for reliability purposes: 150 MW Portfolios - 100 MW new transmission
  200 MW Portfolios - 50 MW new transmission
  250 MW Portfolios - None

Option	Source	Annual Cost for 150 Portfolio
Rent	LADWP*	$5.2 million
Build/Own	New connection to CAISO/SCE^	$3.4 million

- Building and owning appears less expensive, but it carries risks:
  - Cost uncertainties around development and transmission system impacts (yet to be studied)
  - Reliability of new connection to CAISO is uncertain
  - An increase in GWP's single largest contingency changes would increase other costs
- As a result of the risks, portfolios have been developed with **rent** option, with further study on full implications pending

** From Schedules 1, 2, 3, and 7 of LADWP's Open Access Transmission Tariff*
^ Stantec report on new transmission option from GWP Kellogg Substation to SCE Eagle Rock Substation estimated $66 million in upfront costs, plus ongoing O&M

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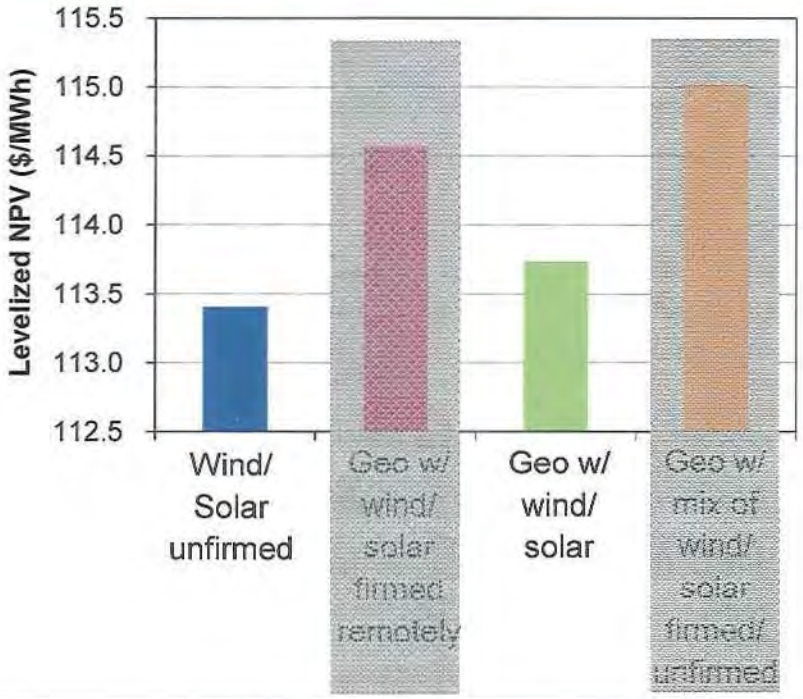
Renewable Screening

- Identified top renewable options: wind from the Northwest, solar PV from the Southwest, and geothermal
- Concluded that firming intermittent resources with Grayson is preferable to firming by a third party

Levelized Portfolio Costs under Renewable Screens



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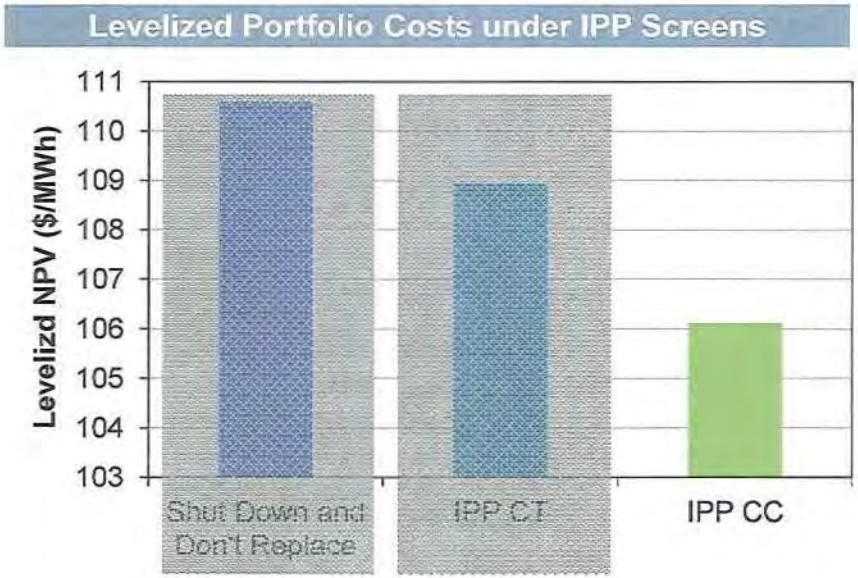
IPP Screening

Most cost-effective option: potential to join a consortium of existing plant owners to develop a new, large natural gas-fired combined cycle ("CC") plant on the site and contract for 50 MW of that new plant



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Storage Options Screening

- **Grid-Scale**: Even with declining cost expectations, battery additions at the grid-scale are not cost-effective at this time
- **Behind-the-Meter-Scale**: Unless customers help pay for a thermal energy storage solution, behind-the-meter storage is not cost-effective
- **Substation-Scale**: Intra-hour regulation and avoided costs are *currently being studied separately* to evaluate storage at the substation level.

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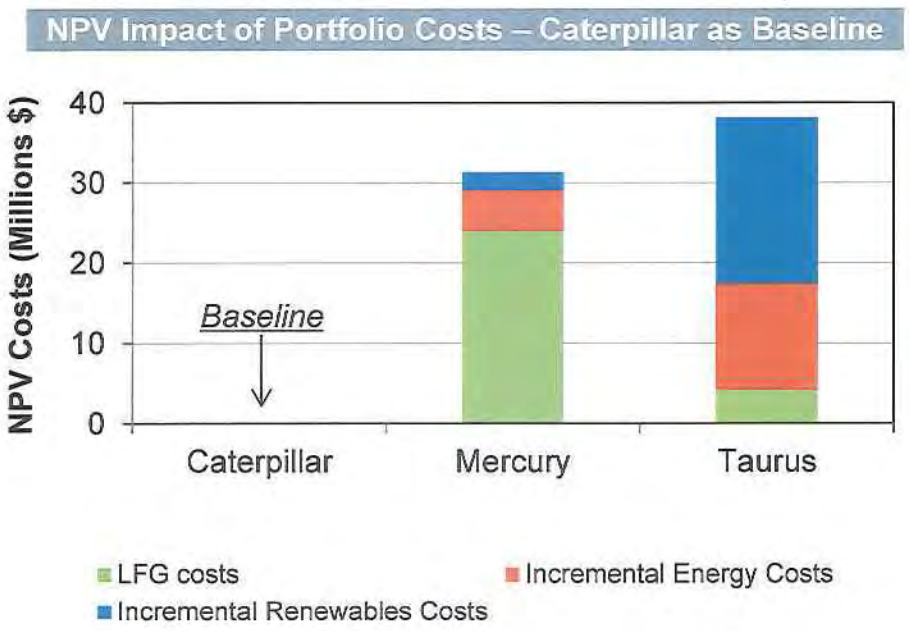
LFG Screening

- Caterpillar option at the Scholl Canyon landfill has lower fixed costs and produces more energy when compared to alternatives



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Based on Screening, Defined Integrated Portfolio Options

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Candidate Portfolio	Grayson	LFG	IPP	Renew-ables
1. Run to Fail	No new investments beyond limited capital extension	No new investment	CC	Wind/ Solar/ Geothermal
2. 150B/ wind/ solar	3 simple cycles	Caterpillar	CC	Wind/ Solar
3. 150B/ wind/ solar/ geo	3 simple cycles	Caterpillar	CC	Wind/ Solar/ Geothermal
4. 200B/ wind/ solar	4 simple cycles	Caterpillar	CC	Wind/ Solar
5. 200B/ wind/ solar/ geo	4 simple cycles	Caterpillar	CC	Wind/ Solar/ Geothermal
6. 200C/ wind/ solar	3 simple cycles 1 combined cycle	Caterpillar	CC	Wind/ Solar
7. 200C/ wind/ solar/ geo	3 simple cycles 1 combined cycle	Caterpillar	CC	Wind/ Solar/ Geothermal
8. 250D/ wind/ solar	2 simple cycles 2 combined cycles	Caterpillar	CC	Wind/ Solar
9. 250D/ wind/ solar/ geo	2 simple cycles 2 combined cycles	Caterpillar	CC	Wind/ Solar/ Geothermal

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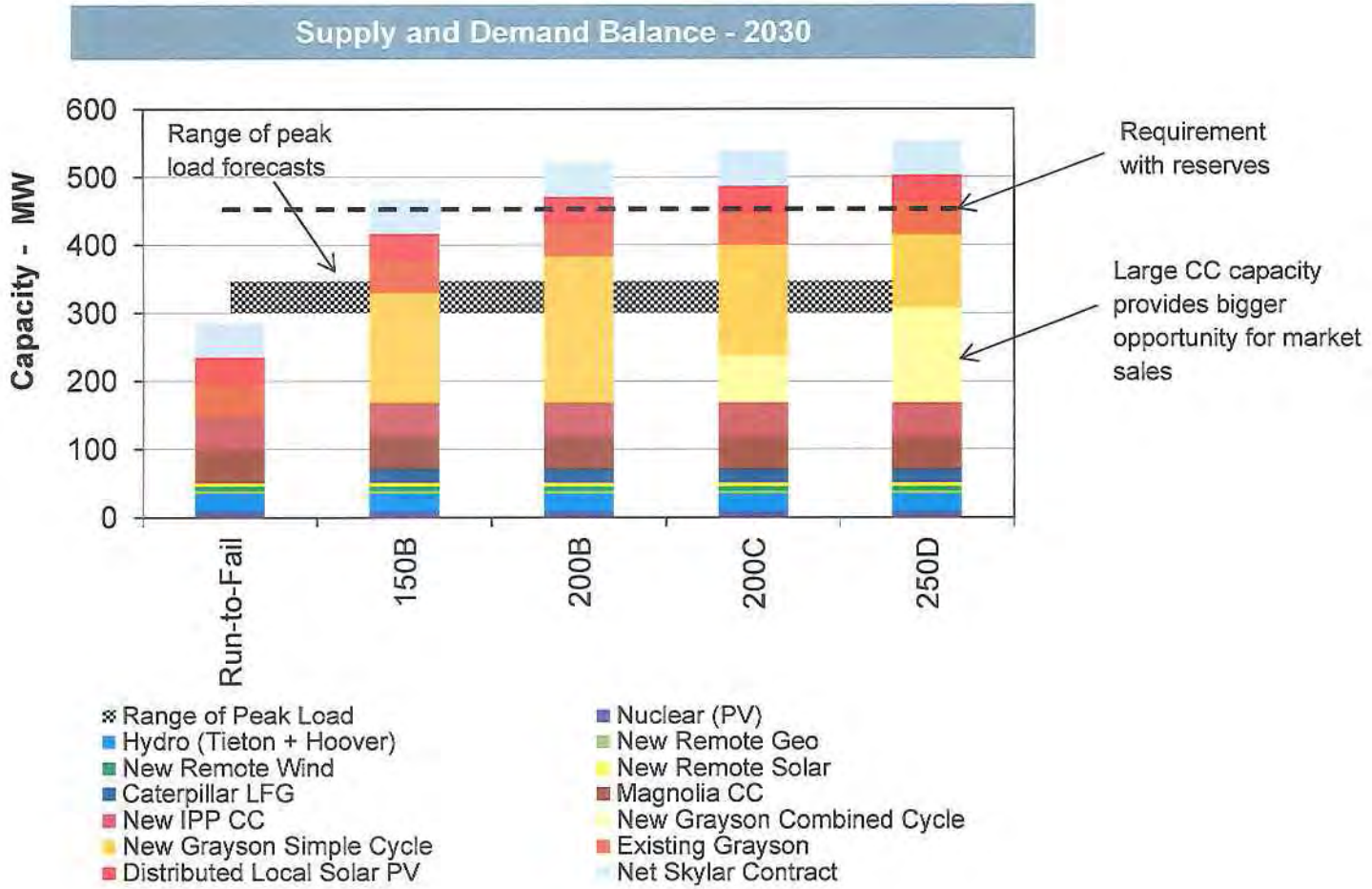
Capacity for Grayson Options



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Energy for Grayson Options

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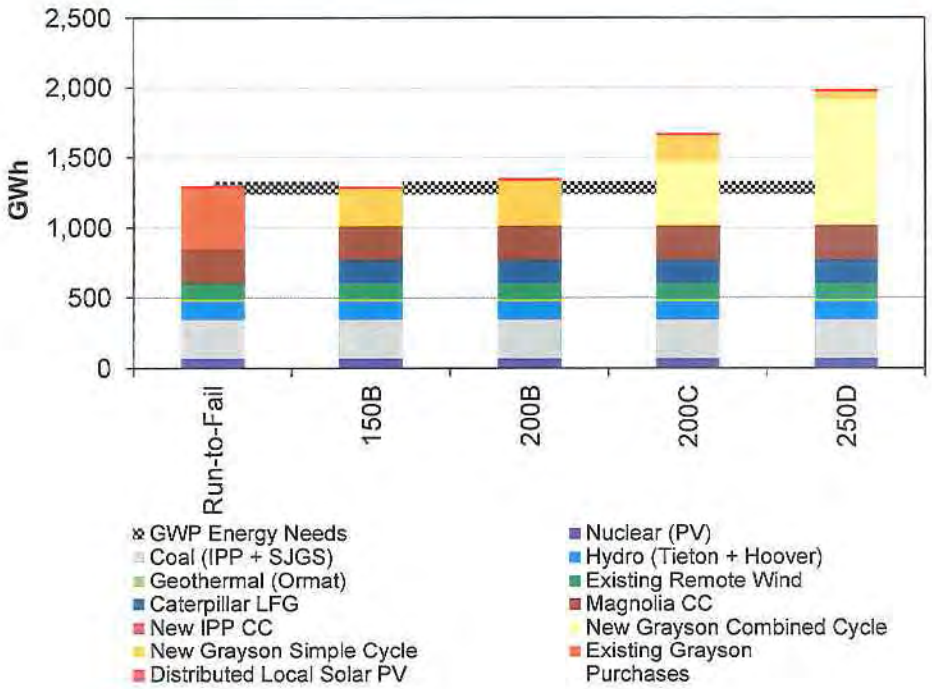
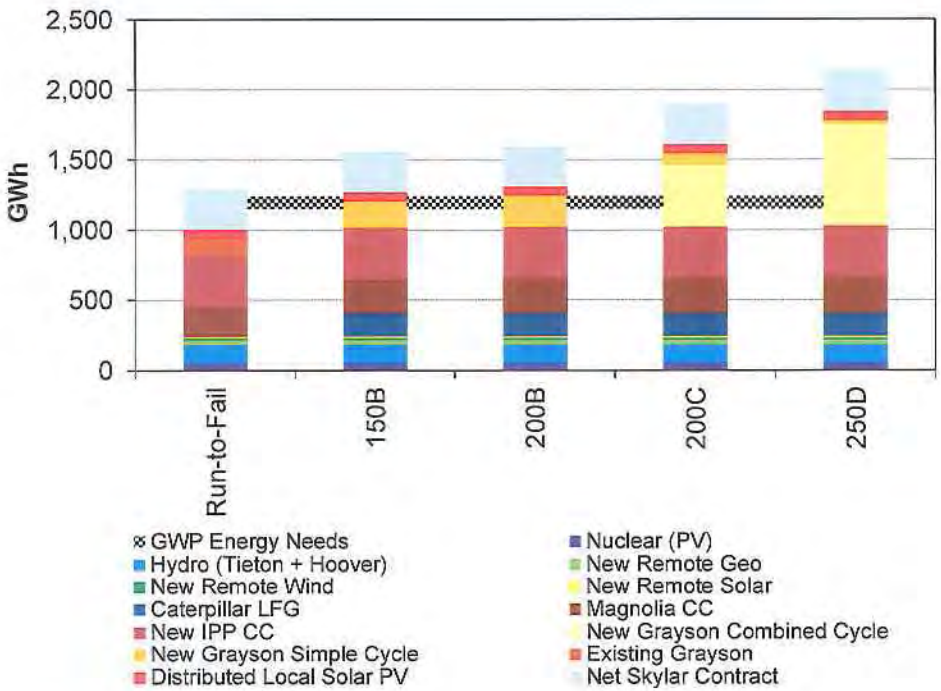
Energy Needs and Resources - 2020



Energy Needs and Resources - 2030



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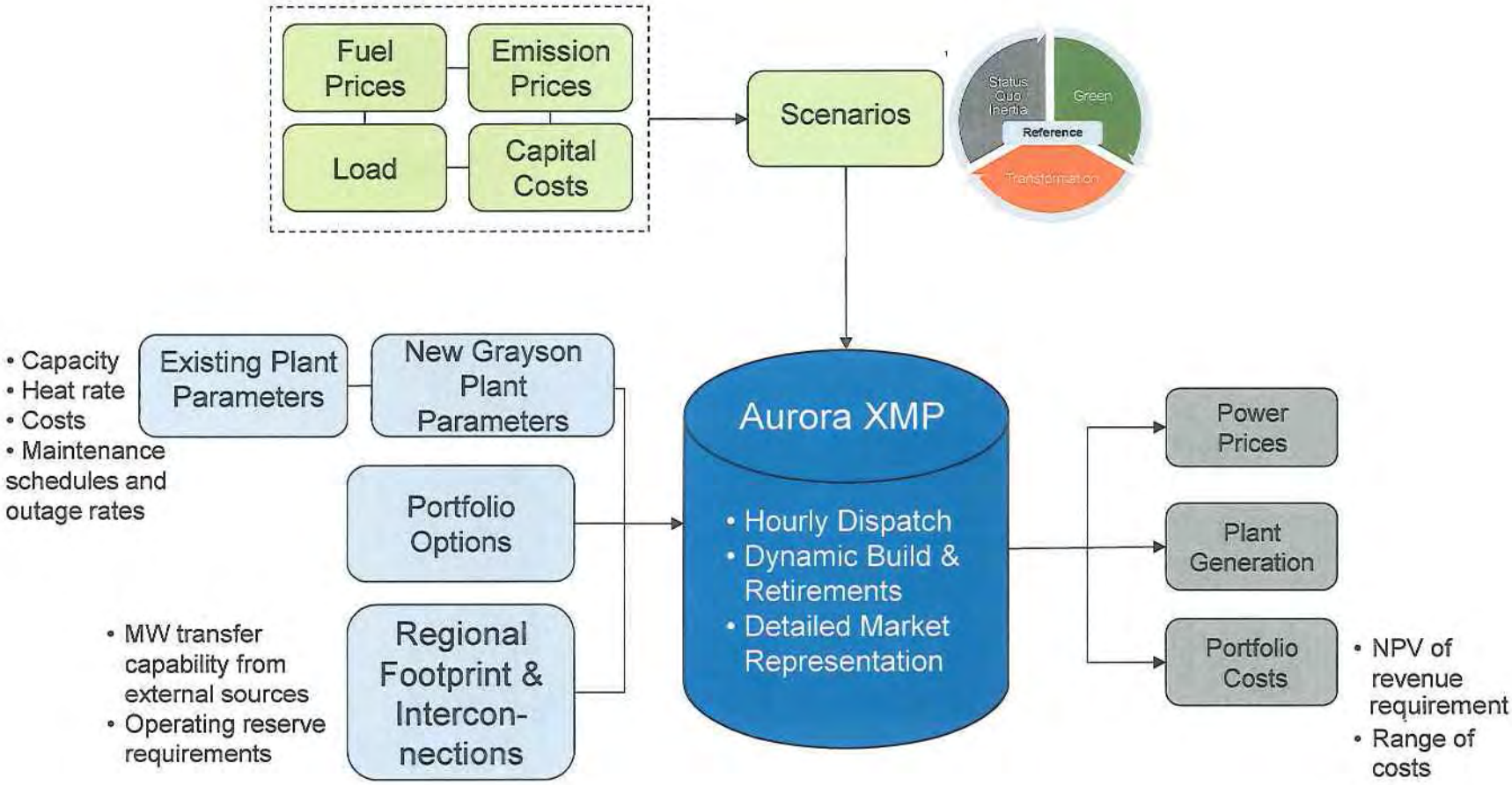
3

Framework for Portfolio Evaluation



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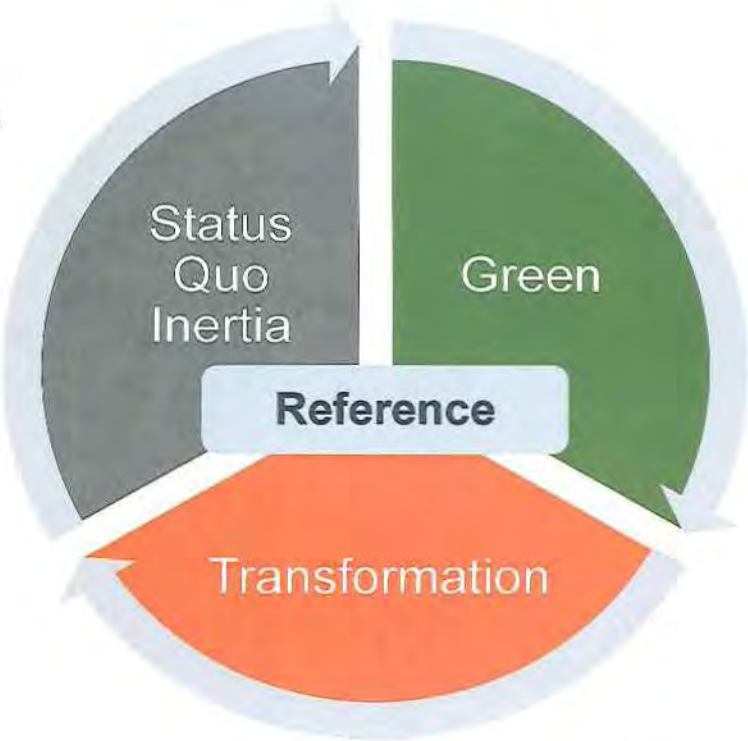
Scenarios to Stress-Test Portfolios

- Gas prices stay low
- Carbon/ RPS regulation at status quo
- Solar PV penetration less than reference
- Customer count grows faster



- CO_2 regs strengthen and allowance prices increase
- Gas demand rises, fracking restrictions implemented, and prices are higher
- CA RPS rises to 50%

- High solar PV and electric vehicle penetration due to declining capital costs of solar and batteries
- TOU rate deployment alters load shape

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Variables in Each Scenario

Variable	Status Quo Inertia	Green	Transformation
Natural Gas Price	↓ Lower production costs and prices	↑ Higher demand for gas and fracking ban	— Same as reference
Carbon Price	↓ Status quo policies remain in place	↑ Stricter regulations and higher compliance costs	— Same as reference
Solar PV Penetration	↓ Lower retail rates and longer payback economics	— Same as reference	↑ Lower technology costs and shorter payback economics
GWP Load Growth	↑ Customer count growth increases	— Same as reference	↓ Peak load declines due to TOU rates; ↑ Sales increase from PHEVs

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4

Summary of Portfolio Results

Portfolios Study Period: 2016-35 All portfolios meet 33% RPS	Cost	Risk/ Rate Stability		Reliability		Environmental Stewardship	Flexibility/ Financial Stability
	Reference Case Levelized NPV* ($/MWh)	Worst Case Cost across Scenarios ($/MWh)	Reliance on market (Net Sales as a % of Total Portfolio Costs- 2020)	Total MWh of Lost Load over 10-year Period	Range Value of Lost Load (millions of 2013$)	Total CO_2 Emissions for owned resources plus purchases 2019-2035 average (000s tons)	Total Capital Investment at Grayson and LFG (millions of $)
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150B/ wind/ solar/ geo	95.3	104.8	0%	2019: 186 2027: 55	2019: 0.25-0.84 2027: 0.07-0.25	407.8	201.4
200B/ wind/ solar	95.8	106.3	1%	2019: 55	2019: 0.07-0.25	428.5	253.1
200B/ wind/ solar/ geo	95.7	105.4	1%	2019: 55	2019: 0.07-0.25	428.8	263.1
200C/ wind/ solar	95.2	103.3	14%	2019: 45	2019: 0.05-0.20	514.1	300.1
200C/ wind/ solar/ geo	95.1	102.5	14%	2019: 45	2019: 0.05-0.20	514.6	300.1
250D/ wind/ solar	94.1	101.1	27%	2019: 28	2019: 0.04-0.13	601.7	337.1
250D/ wind/ solar/ geo	94.0	100.2	27%	2019: 28	2019: 0.04-0.13	603.0	337.1

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Key Findings: Grayson Repower and Renewables

- The Run-to-Fail option is not feasible: high cost and unacceptable risk to local reliability
- The 150 MW option has relatively low capital investment, but some reliability risk
- The 250 MW option has the highest capital investment but lowest range of costs; it has highest reliance on off-system sales in order to keep costs down.
- The 200 MW option performs relatively well across all metrics, but doesn't "win" in any.
- Portfolios with diverse remote renewables (wind, solar, and geothermal) are slightly lower cost and have greater technological diversity than portfolios that just have wind and solar

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Costs of Major Grayson Options

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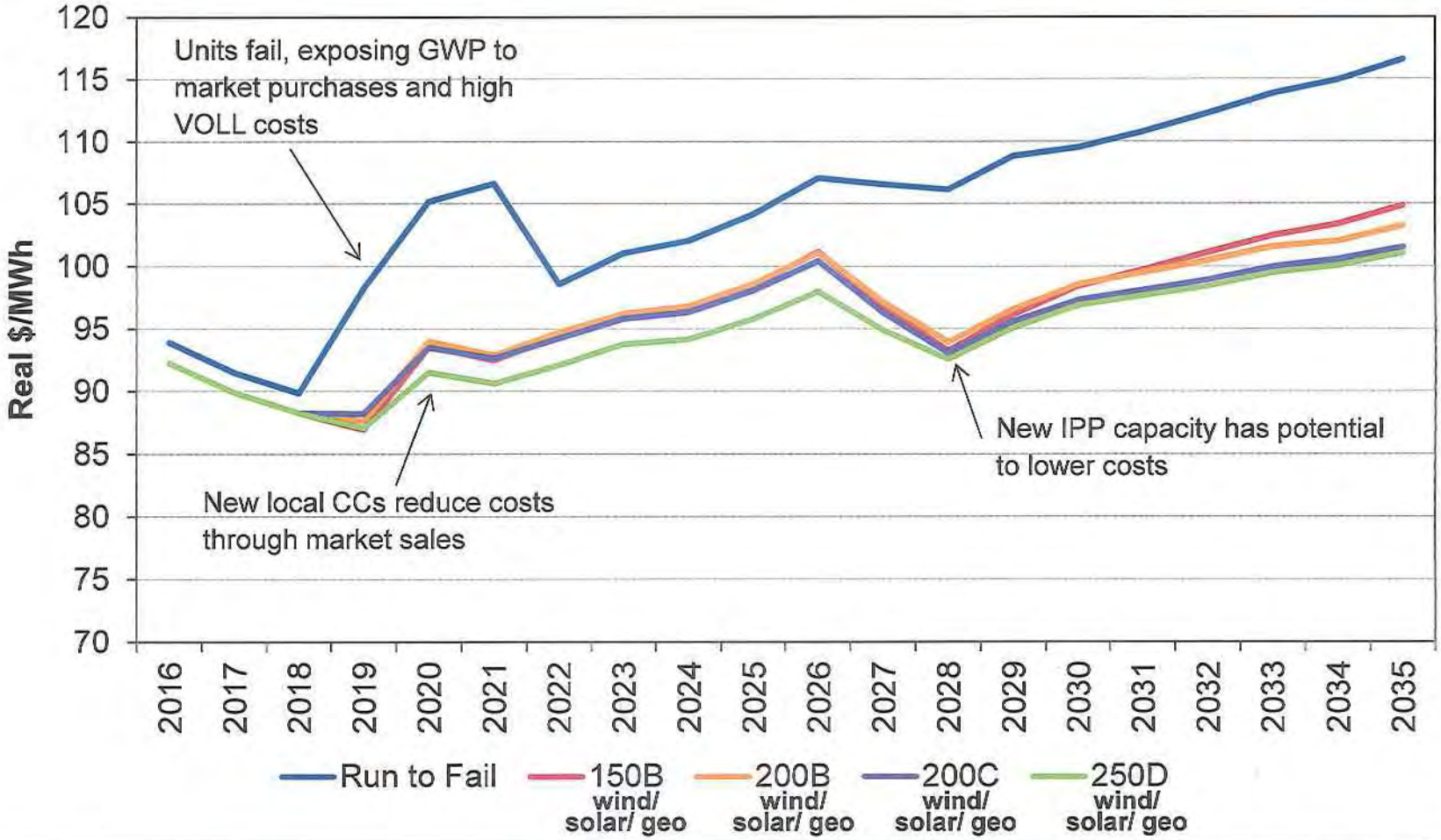
Annual Portfolio Costs (Real $/MWh) – Reference Case Scenario



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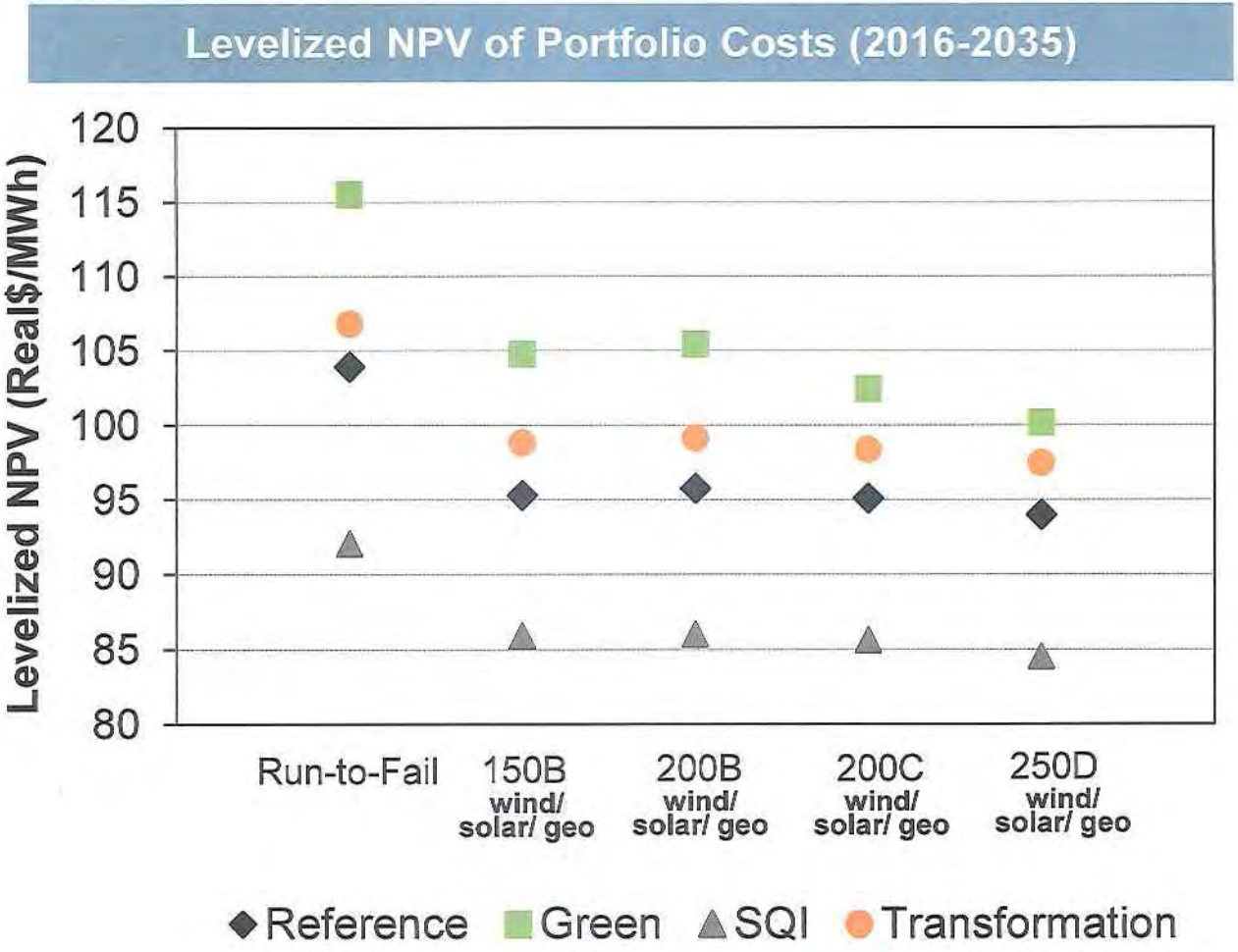
Grayson 250D Portfolio: Lowest Cost and Lowest Range of Costs



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Key Findings by Metric for Grayson

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Cost

- Run-to-fail portfolio is highest cost; 250D portfolio is lowest cost

Risk

- 250D portfolio offers hedge against high market prices; more local generation provides insurance against catastrophes, such as earthquakes
- By 2020, 250D portfolio relies heavily on market sales; partner recommended

Reliability

- Run-to-fail portfolio violates reliability standards by 2019 and later; 150B portfolio faces moderate reliability risks; larger portfolios meet reliability guidelines

Environmental Stewardship

- Portfolios with more local generation have highest CO_2 emission footprint

Financial Flexibility

- 250D portfolio requires the highest capital expenditures and thus new debt; partner recommended

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Key Findings: LFG Combustion

- Existing combustion at Grayson is inefficient and more expensive than new combustion equipment would be
- Pipeline transporting LFG from Scholl Canyon to Grayson is subject to increasing regulatory risks and maintenance costs
- Separating LFG combustion from Grayson and moving it to Scholl Canyon avoids tens of millions of dollars in air emissions permit costs
- Installing new, efficient combustion at Scholl could double the renewable energy produced by Glendale's LFG
- Avoided costs may be close to incremental costs, minimizing any rate impact
- Recommendation: move LFG combustion to Scholl Canyon

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Recommended Actions

- Grayson Repower
  - Proceed with repower
  - Find long-term municipal partner for share of 250 MW option
- LFG Combustion
  - Proceed with new generation at Scholl Canyon
- RPS Compliance
  - Retire Grayson boilers; increase energy from LFG; prepare to integrate new renewables with repowered Grayson
- Energy Storage
  - Complete intra-hour analysis and develop recommendations
- Transmission Capacity
  - Continue study of new transmission connection, but plan to buy from LADWP unless risks can be controlled

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Recommended Actions

- Coal Replacement
  - Replace San Juan with generic market energy and renewables
  - Develop options for IPP renewal
- GHG Compliance
  - Build inventory of free allowances between now and 2020
- Distributed Generation (Solar PV)
  - Monitor build-out and prepare for system impacts
- Retail Rates
  - Develop plan for changes in rate design post-2018; investigate TOU rates
- Community Outreach
  - Develop message strategy, esp. for CEQA compliance

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Discussion and Questions

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Appendix I

Screening Analysis Details

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Answers for infrastructure and cities.

Initial Step Required Identification of Feasible Options at Grayson Site

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- Stantec identified nine distinct configurations using combinations of Wartsila engines and LM6000 simple cycle and combined cycle additions in three general capacity sizes: 150 MW, 200 MW, and 250 MW.

Configuration Name	Wartsila 18V50SG		LM6000PG Sprint Simple Cycle		LM6000PG Sprint 1x1 Combined Cycle	
	Number of Units	Capacity (MW)	Number of Units	Capacity (MW)	Number of Units	Capacity (MW)
150A	3	55.0 MW	2	107.8 MW		
150B			3	161.7 MW		
200A	3	55.0 MW	3	161.7 MW		
200B			4	215.5 MW		
200C			3	161.7 MW	1	70.1 MW
250A	3	55.0 MW	4	215.5 MW		
250B			5	269.4 MW		
250C			4	215.5 MW	1	70.1 MW
250D			2	107.8 MW	2	140.2 MW

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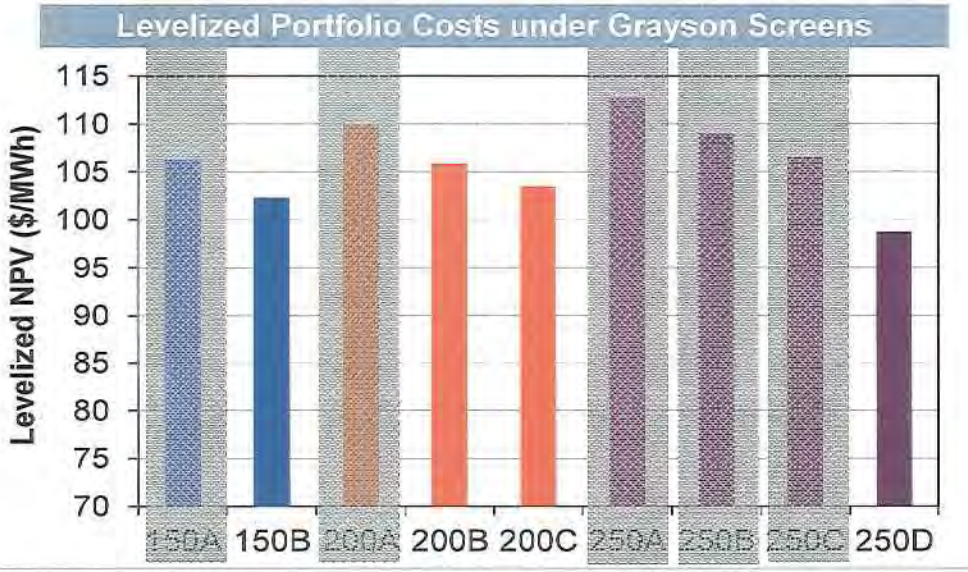
Screening Analysis Eliminated Wartsila Option and Reduced the Candidate List to Four

- The Wartsila "A" family (150A) is higher cost than the other LM6000 options within each capacity grouping, as a result of the very high minimum capacity level required for Wartsila operations.
- The 250D portfolio achieves the lowest cost as a result of significant market sales opportunities that develop with 140 MW of efficient combined cycle capacity.
  - 250A and 250B build only simple cycles and cannot expect to recover costs through market sales
- Even with additional transmission cost requirements, the 150B portfolio is the second lowest cost, but has reliability issues
- The 200B and 200C portfolios are within the top four options, although both are slightly higher than the best-performing 150 and 250 portfolios at the screening phase.



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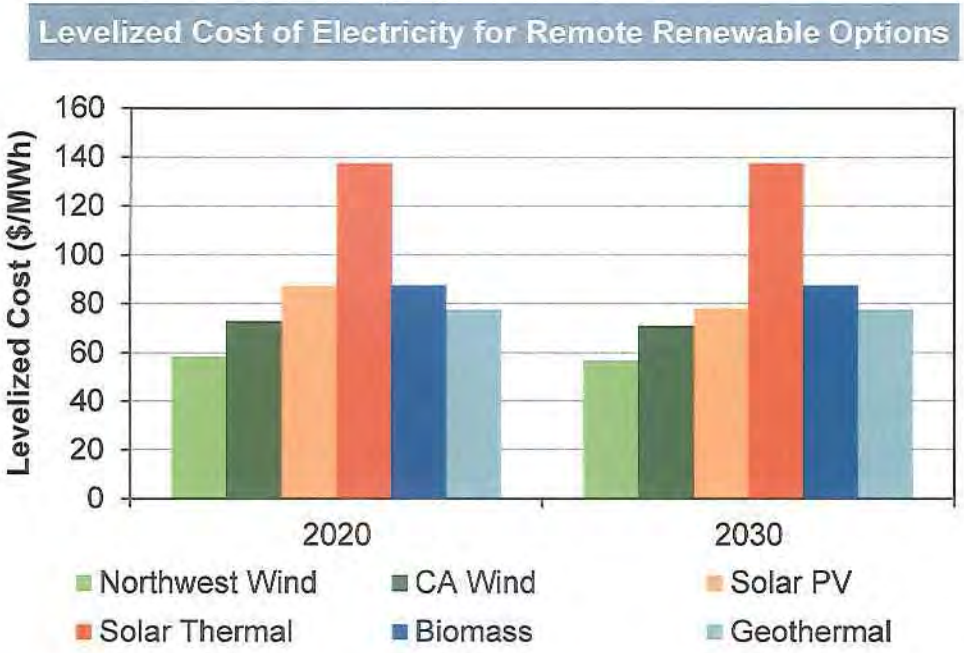
Remote Capacity Additions

- Remote renewable options were assessed as if developed by an independent power producer, selling under contract to GWP
- Screening analysis first narrowed options to Northwest wind, solar PV, and geothermal



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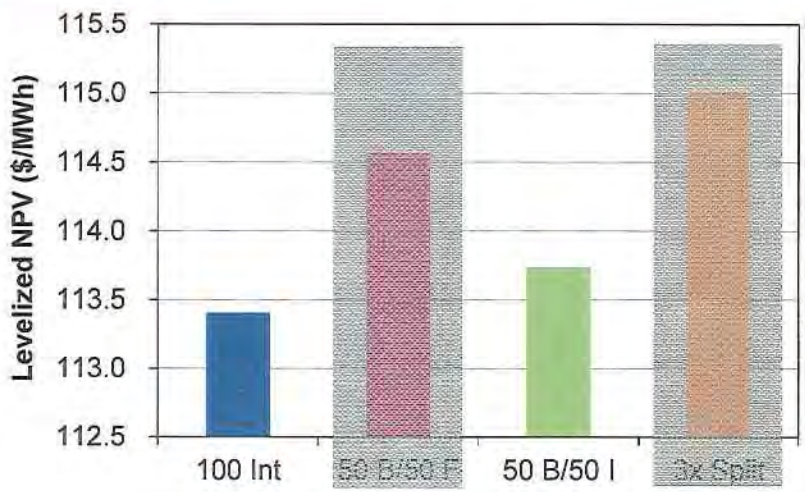
Renewable Portfolios Were Constructed around Different "Themes" for Further Screening

- 100% intermittent supplies (50% from NW Wind, 50% from SW solar PV);
- 50% baseload geothermal and 50% *firmed* intermittent supplies (50% from NW Wind, 50% from SW solar PV with a gas CT to firm supply during lower production hours);
- 50% baseload geothermal and 50% intermittent supplies (50% from NW Wind, 50% from SW solar PV) with no explicit firming costs beyond local generation resources;
- An even split between baseload geothermal, *firmed* intermittent, and intermittent supplies.

Levelized Portfolio Costs under Renewable Screens



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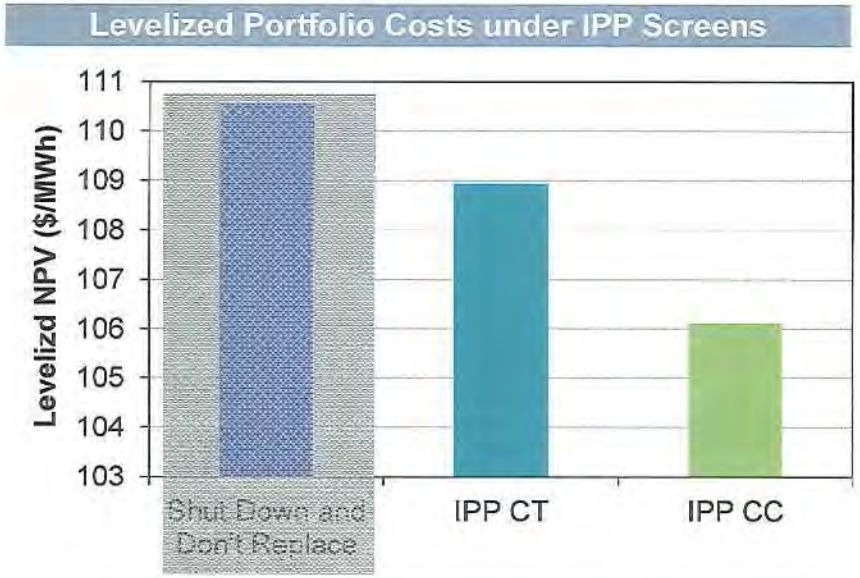
Replacement Options for Coal at IPP

- Join a consortium of existing plant owners to develop a new, large natural gas-fired combined cycle ("CC") plant on the site and contract for 50 MW of that new plant;
- Work with another entity to develop a smaller LMS100 gas-fired combustion turbine (100 MW "CT") on the site and split that capacity 50/50; or
- Let IPP shut down without replacement with new generating capacity, lose all existing transmission rights, and acquire new transmission through lease from LADWP.



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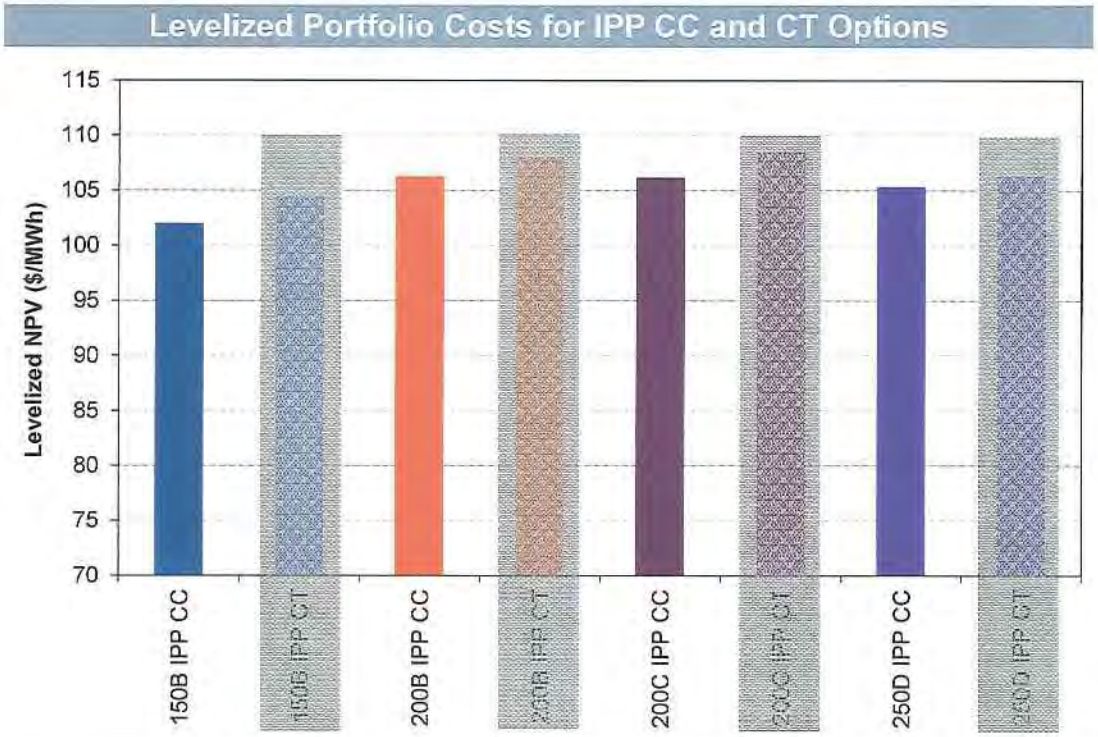
Combined Cycle vs. Peaker Options

- CC and CT options were evaluated against each of the four leading Grayson options
- The CC replacement remained lowest cost across the board



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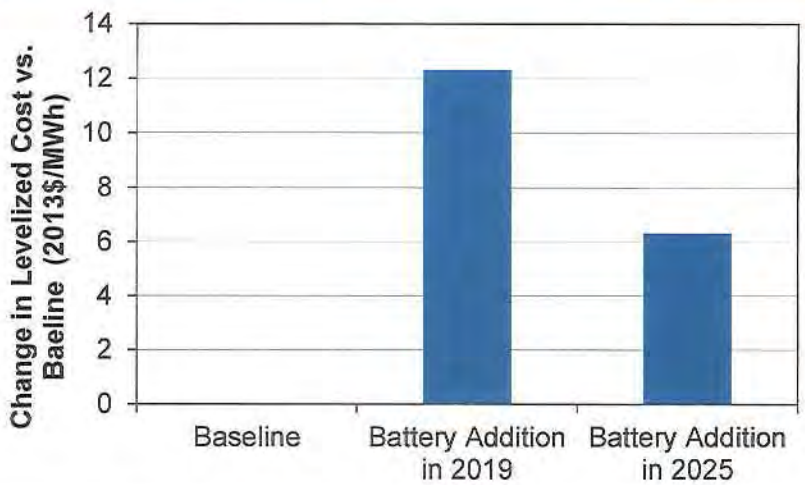
Storage

Grid-Scale Storage Options Were Evaluated over Time

- Battery additions to provide firming resource at the grid-scale were evaluated over time
- Even with declining cost expectations, the battery additions are not cost-effective
- **Note: this ignores intra-hour avoided costs, which will be studied separately**

Category	Characteristic
Storage Duration	4 Hours
Round Trip Efficiency	85-90%
Battery Life	11-15 Years
FOM (2013$/kW-yr)	101
2015 Cost (2013$/kW)	4,681
2019 Cost (2013$/kW)	1,500
2025 Cost (2013$/kW)	1,000

Levelized Portfolio Cost Differences for Battery Screens



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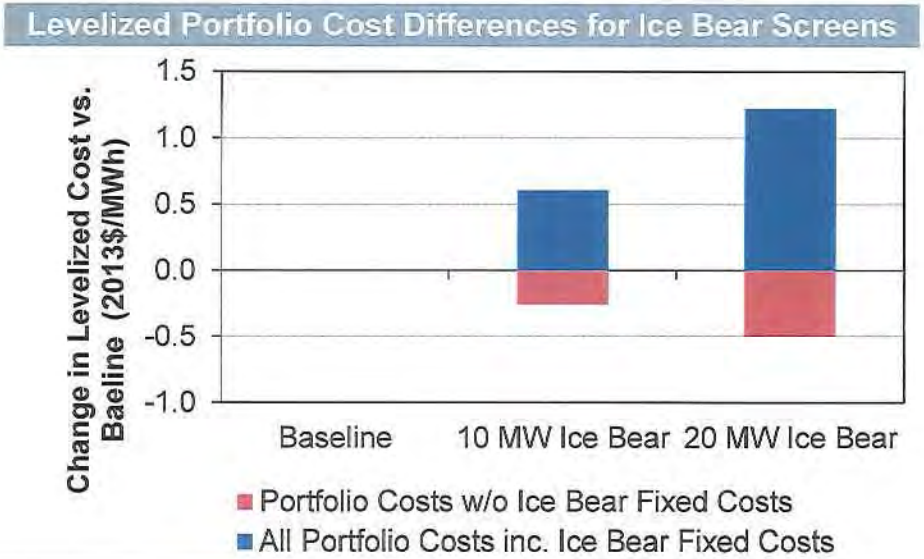
Behind-the-Meter Storage Option

- Load shifting contributes to a savings on the order of 0.1% to 0.2% for 10 MW and 20 MW additions, respectively.
- The capital costs plus incremental operating costs, however, overwhelm this savings under the assumption that GWP pays all costs of installation and operation.



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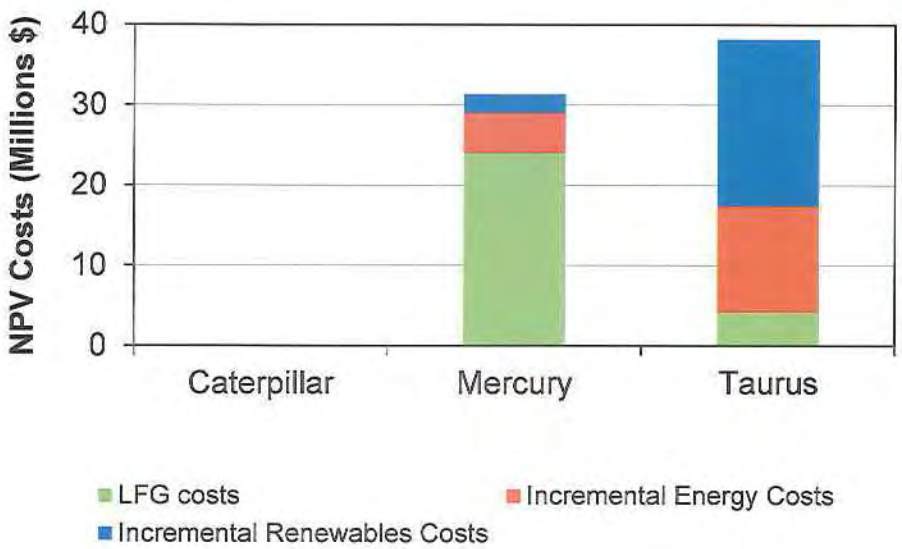
LFG

Caterpillar Option Performs Better than Solar Mercury or Solar Taurus Options

	Annual Renewable Generation (MWh)	Equipment cost (Millions $)	O&M Cost (Millions $)	Annual Equipment Cost Payment (Millions $)	Annual Fixed Costs (Millions $)
Mercury	153,300	22.1	2.8	1.1	3.8
Taurus	131,400	17.2	1.7	0.8	2.5
Caterpillar	165,564	16.3	1.8	0.8	2.6

NPV Impact of Portfolio Costs – Caterpillar as Baseline



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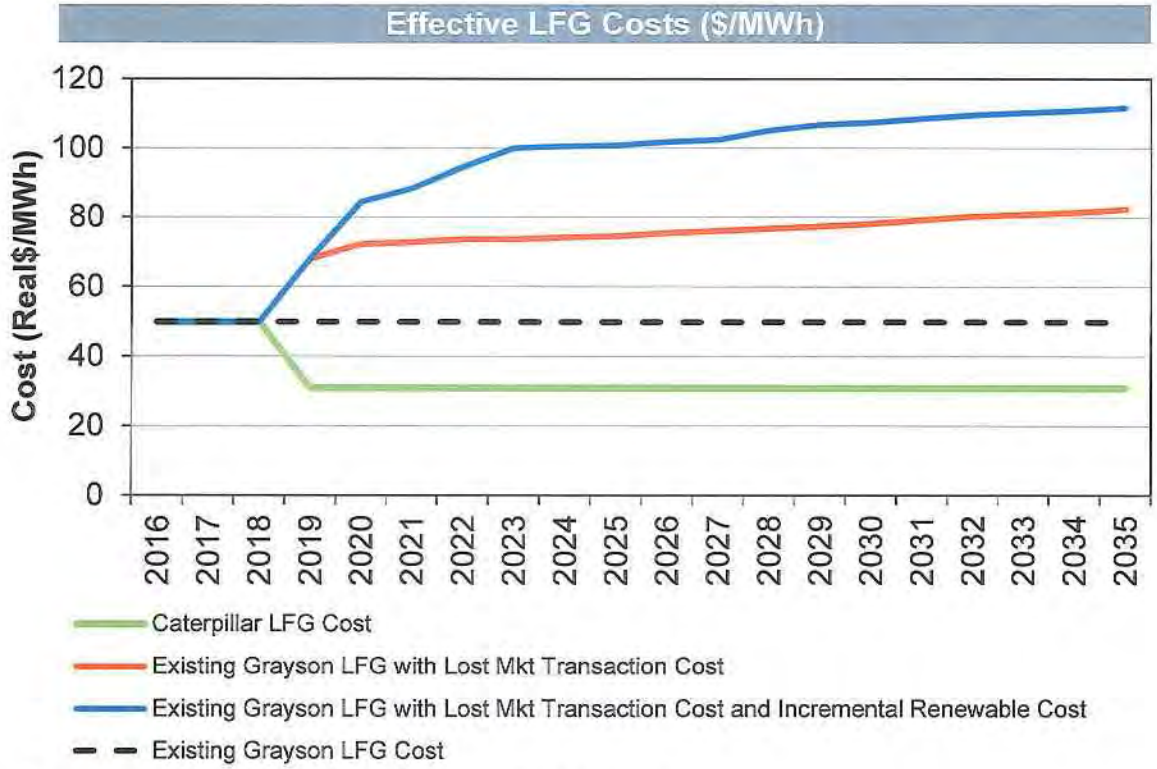
Caterpillar Option Provides Significant Savings against Status Quo

- The Caterpillar LFG option reduces costs significantly vs. current operations, especially after taking into account avoided energy and renewable benefits



**Note that costs include a payment to the City for the landfill gas of $2.5 million per year.*

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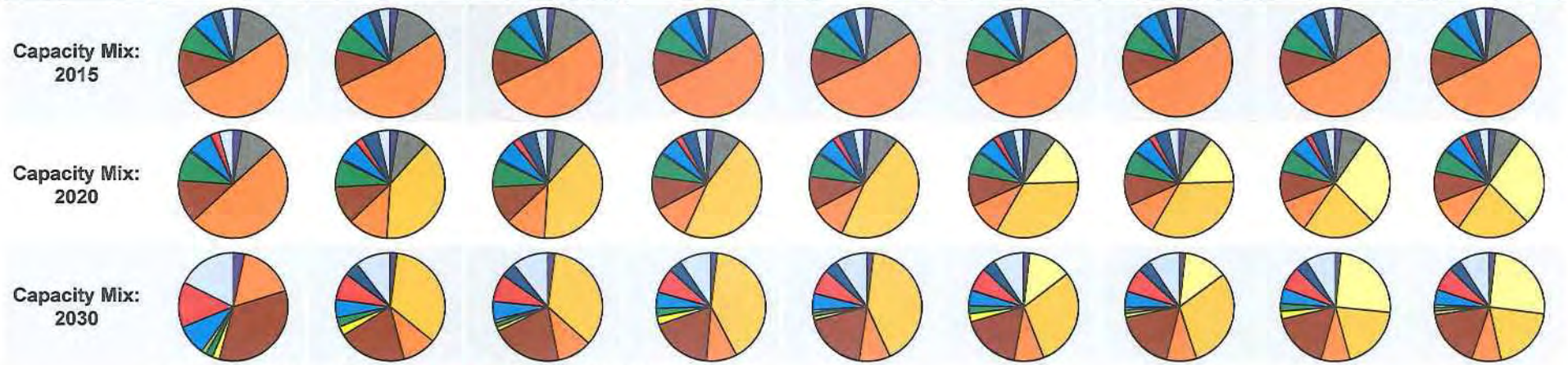
Overview of All Portfolios after Screening

All capacity represented by installed MW



Total Capacity Additions / Losses (MW) by 2030

	Run to Fail		150B/ wind/ solar		150B/ wind/ solar/ geo		200B/ wind/ solar		200B/ wind/ solar/ geo		200C/ wind/ solar		200C/ wind/ solar/ geo		250D/ wind/ solar		250D/ wind/ solar/ geo	
Nuclear																		
Coal		-57		-57		-57		-57		-57		-57		-57		-57		-57
Local Gas – LM6000 CC											+70.1		+70.1		+140.2		+140.2	
Local Gas – LM6000 CT			+161.7		+161.7		+215.5		+215.5		+161.7		+161.7		+107.8		+107.8	
Local Gas – Existing CT/ST		-174		-174		-174		-174		-174		-174		-174		-174		-174
Remote Gas – CC (Mag/IPP)	+50		+50		+50		+50		+50		+50		+50		+50		+50	
Remote Solar	+6		+13		+6		+13		+6		+13		+6		+13		+6	
Remote Wind	+6	-33	+13	-33	+6	-33	+13	-33	+6	-33	+13	-33	+6	-33	+13	-33	+6	-33
Remote Geo	+4	-2.1		-2.1	+4	-2.1		-2.1	+4	-2.1		-2.1	+4	-2.1		-2.1	+4	-2.1
Remote Hydro																		
Local DER - Solar	+36.8		+36.8		+36.8		+36.8		+36.8		+36.8		+36.8		+36.8		+36.8	
LFG		-11	+20.2	-11	+20.2	-11	+20.2	-11	+20.2	-11	+20.2	-11	+20.2	-11	+20.2	-11	+20.2	-11
Net Skylar	+35		+35		+35		+35		+35		+35		+35		+35		+35	

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Appendix II

Scenario Details

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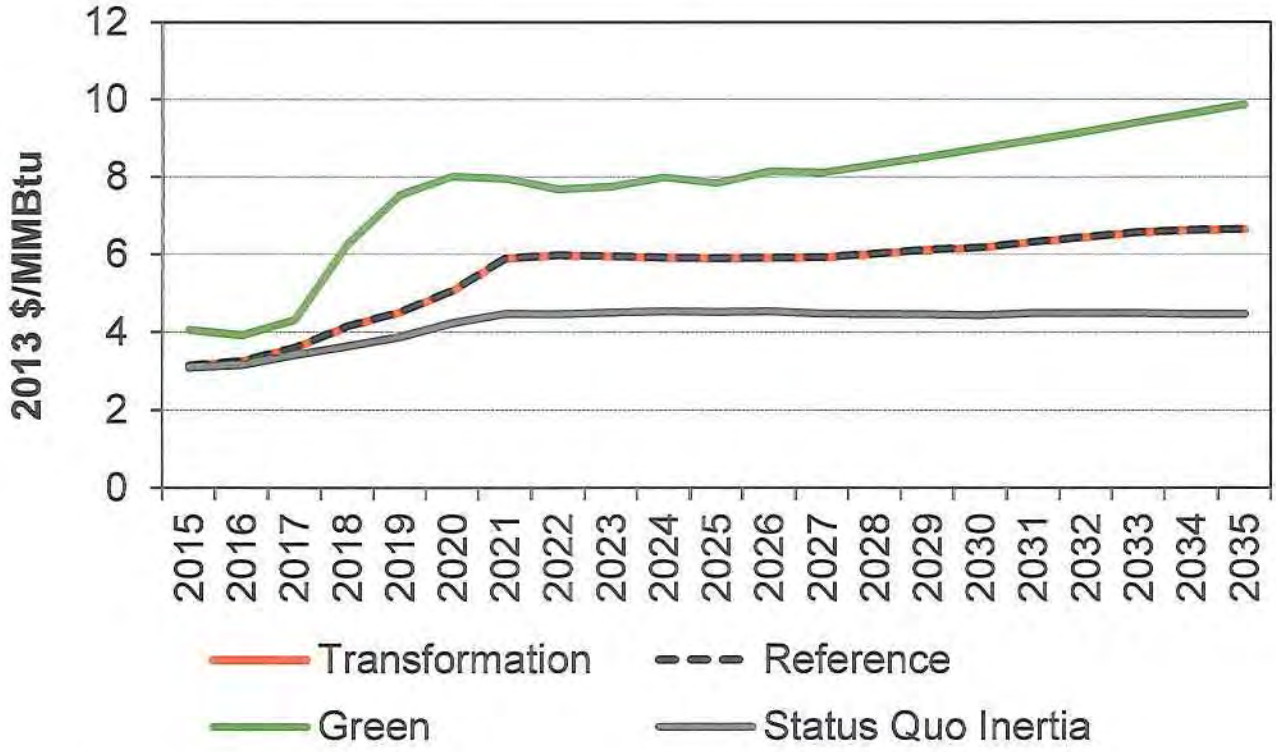
Answers for infrastructure and cities.

Natural Gas Prices across Scenarios

SQI: abundant supply with production costs low

Green: high demand for gas and fracking restrictions



Note that the Transformation scenario uses the Reference Case gas price projections.

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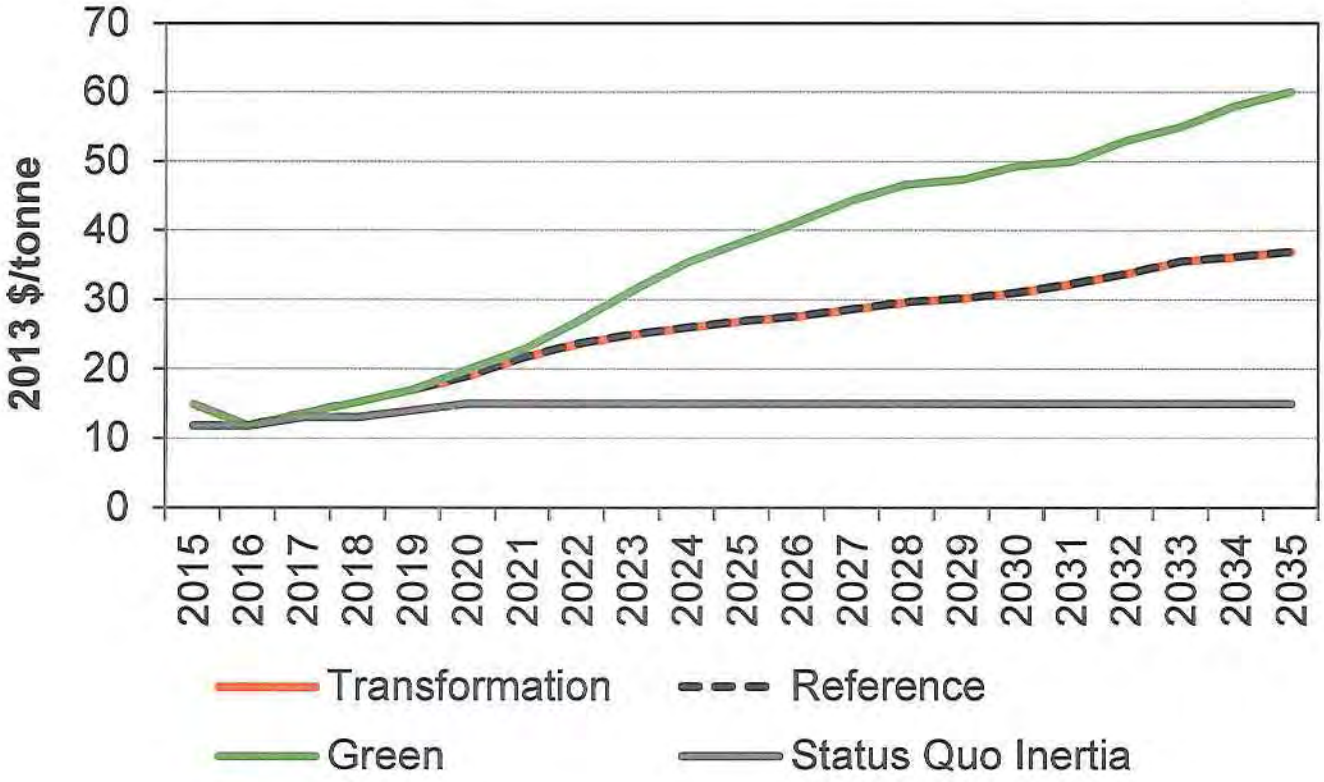
Carbon Prices across Scenarios

SQI: cost-effective reductions and efficient changes in other sectors

Green: more stringent caps and higher gas prices drive higher carbon costs



Note that the Transformation scenario uses the Reference Case carbon price projections.

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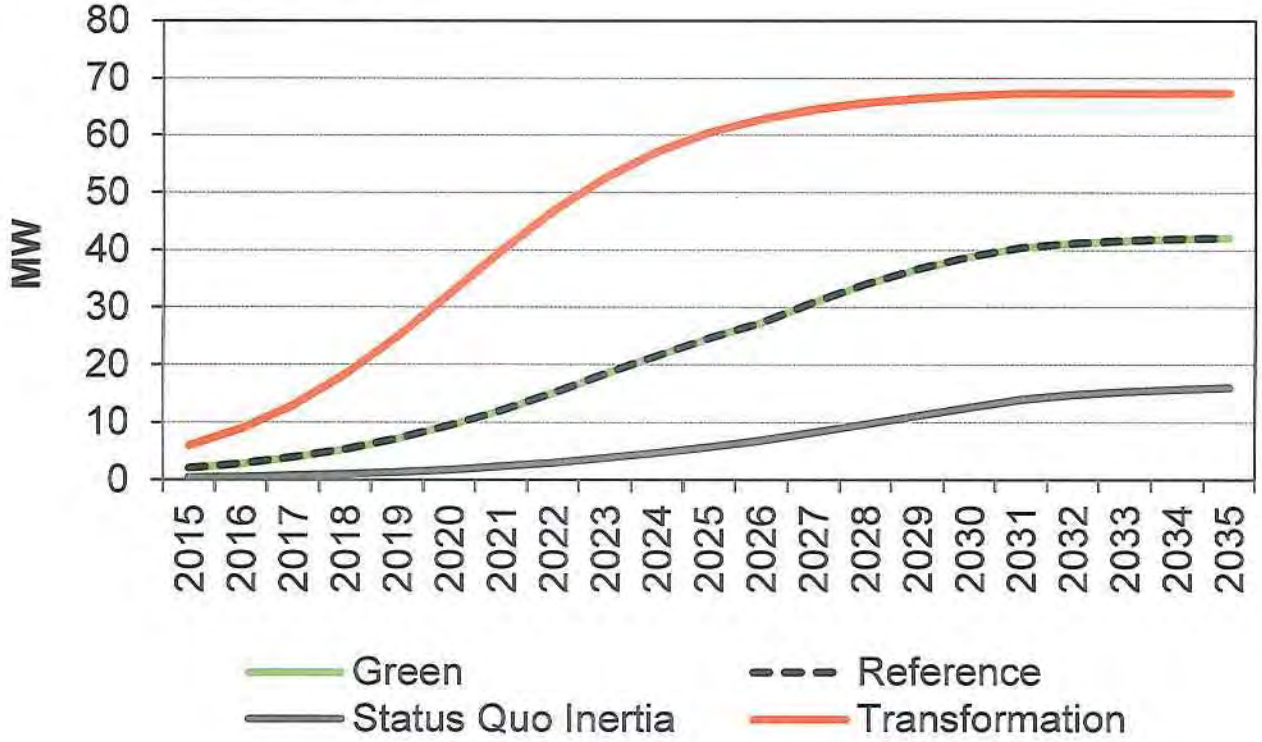
Solar PV Penetration across Scenarios

SQI: costs of electricity lower; payback period higher

Transformation: solar PV and battery costs decline; other technology and information enables adoption



**Note that the Green scenario uses the Reference Case solar PV penetration levels.*

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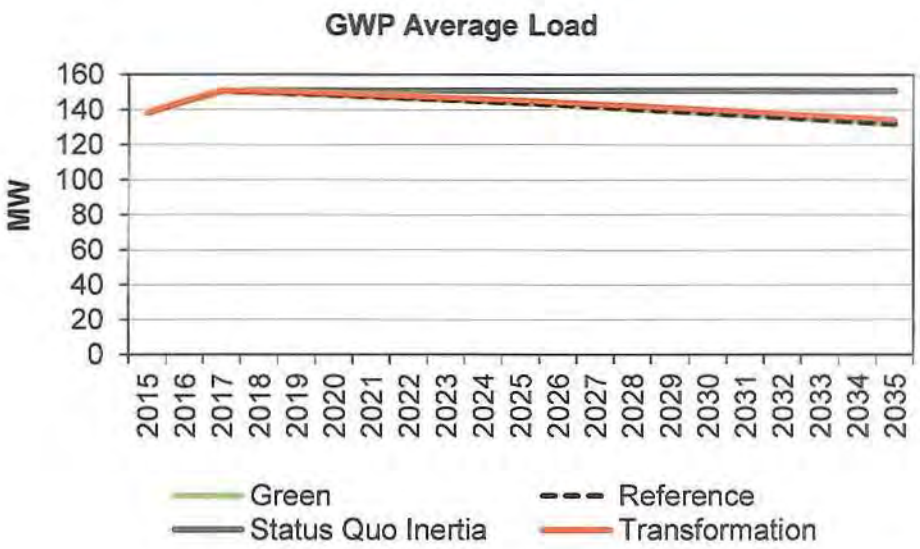
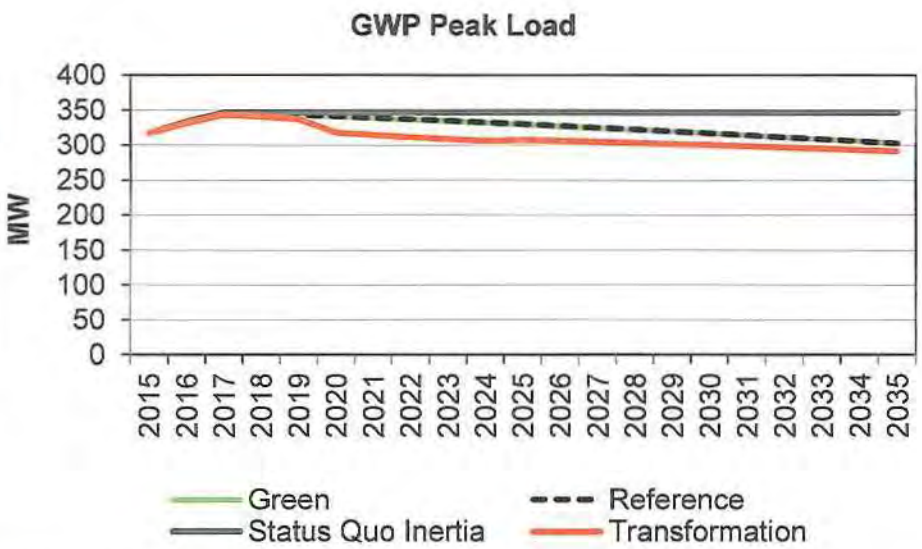
Load Growth across Scenarios

SQI: customer count increases continue as a result of re-development and increased population density

Transformation: TOU rate adoption, but electric vehicle penetration is higher as a result of batter cost declines





**Note that the Green scenario uses the Reference Case load growth levels.*

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Appendix III

Portfolio Analysis Details

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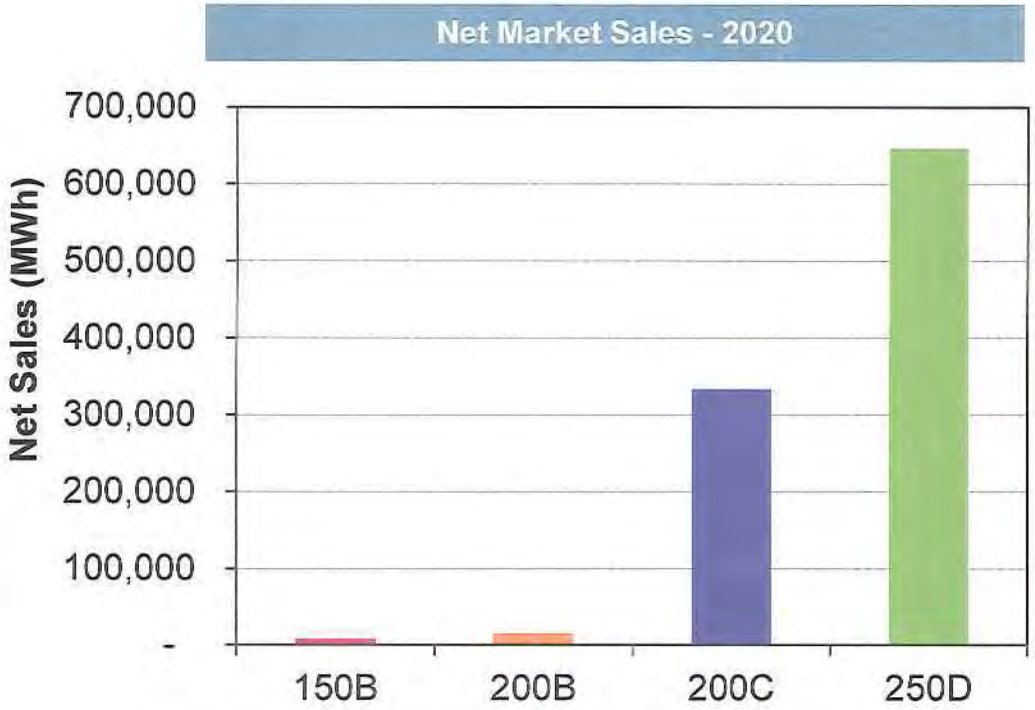
Answers for infrastructure and cities.

Portfolios with Local Combined Cycles Produce Significant Off-System Sales

- In 2020, while 150B and 200B (portfolios with only simple cycle LM6000s) have limited net transactions with the outside market, the CC portfolios generate significant revenues to offset larger capital costs



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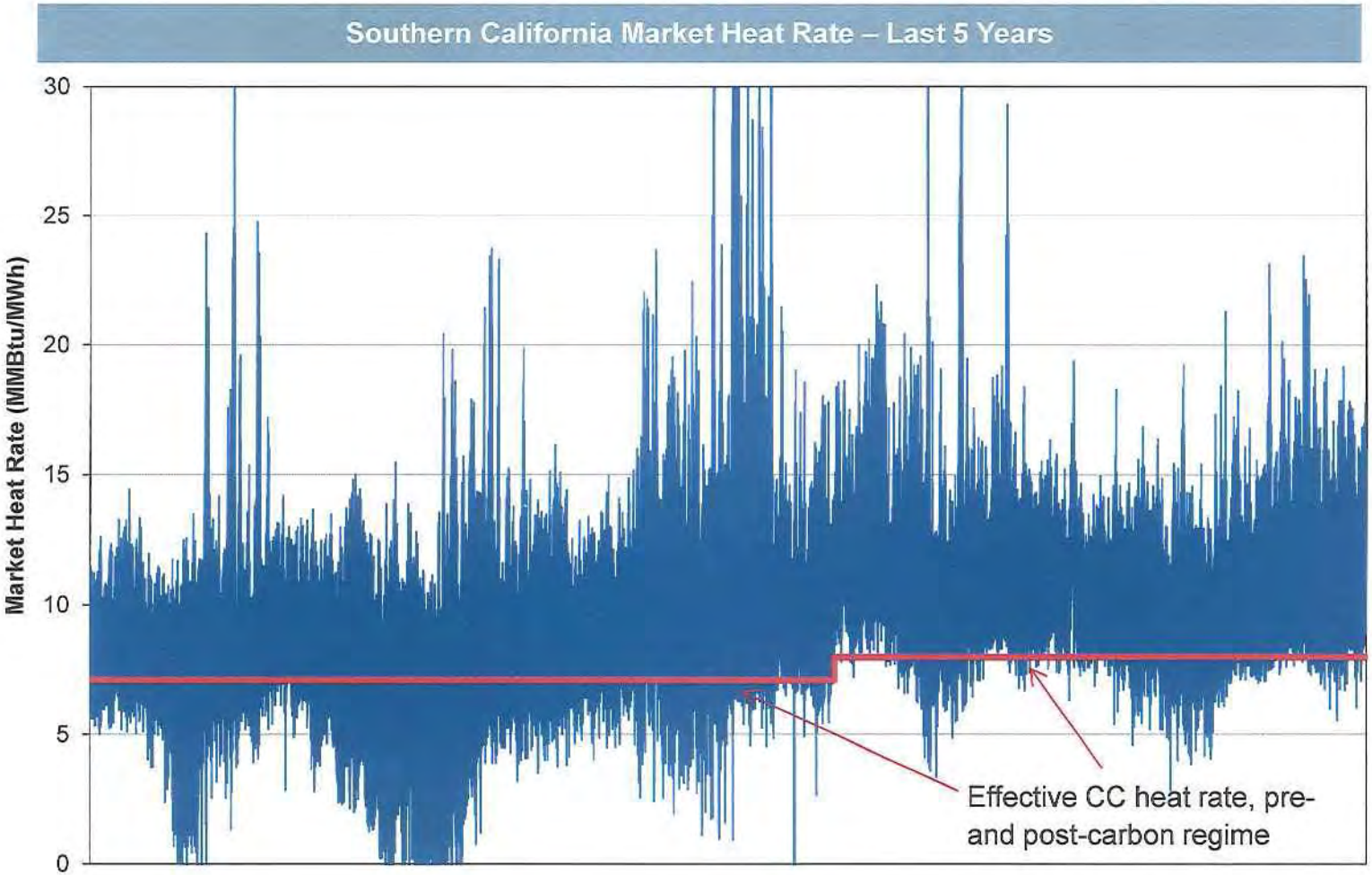
Market Volatility Can Pose Dispatch and Sales Risks for CC Portfolios



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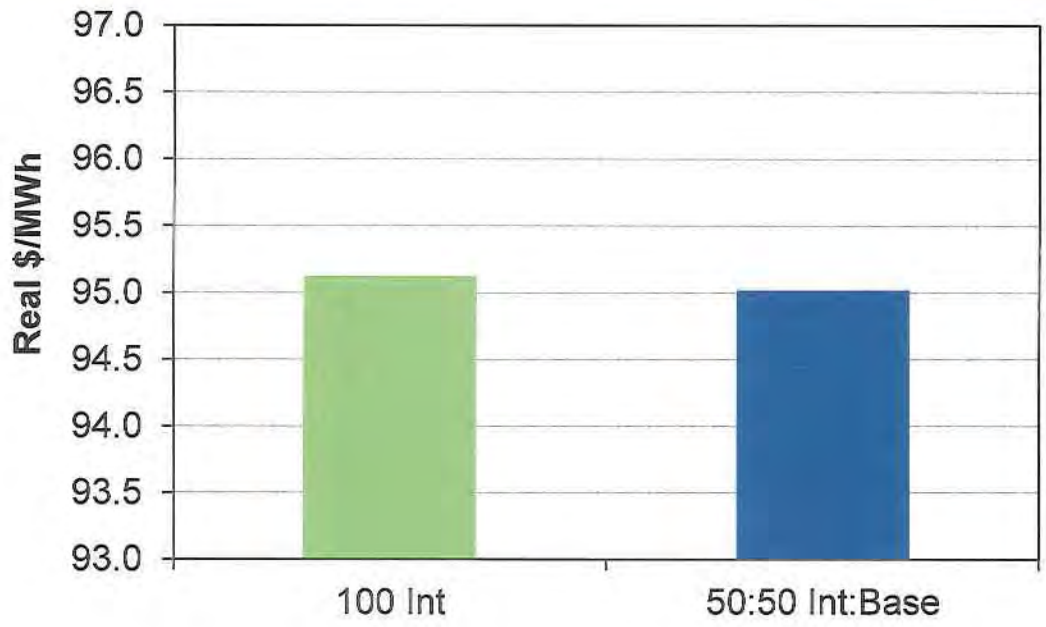
Diverse Remote Renewables are Slightly Lower Costs

- Across all scenarios, the portfolio options that obtain renewables from wind, solar, and geo are slightly lower cost than the pure wind/solar mix

Portfolio Cost Average for Renewable Strategies – Reference Case



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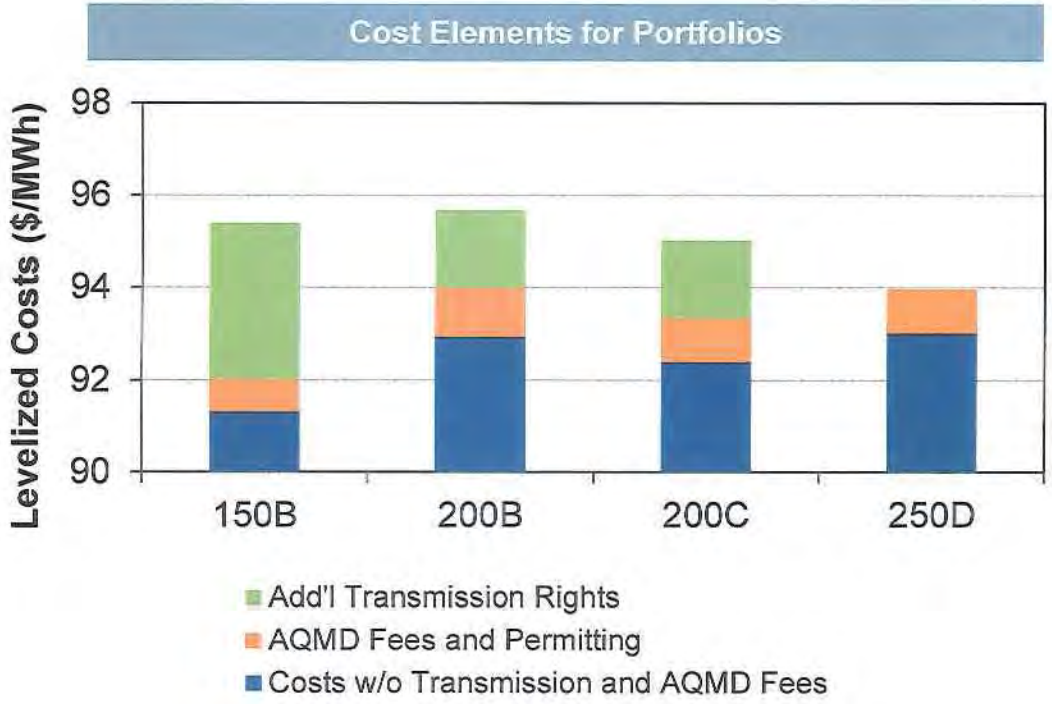
Extra Transmission Costs Impact the 150 and 200 Families

- If the 150B portfolio did not face additional charges associated with paying for additional transmission rights to access external energy, its overall portfolio costs would be much closer to the other options



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Appendix IV

LOLE Study

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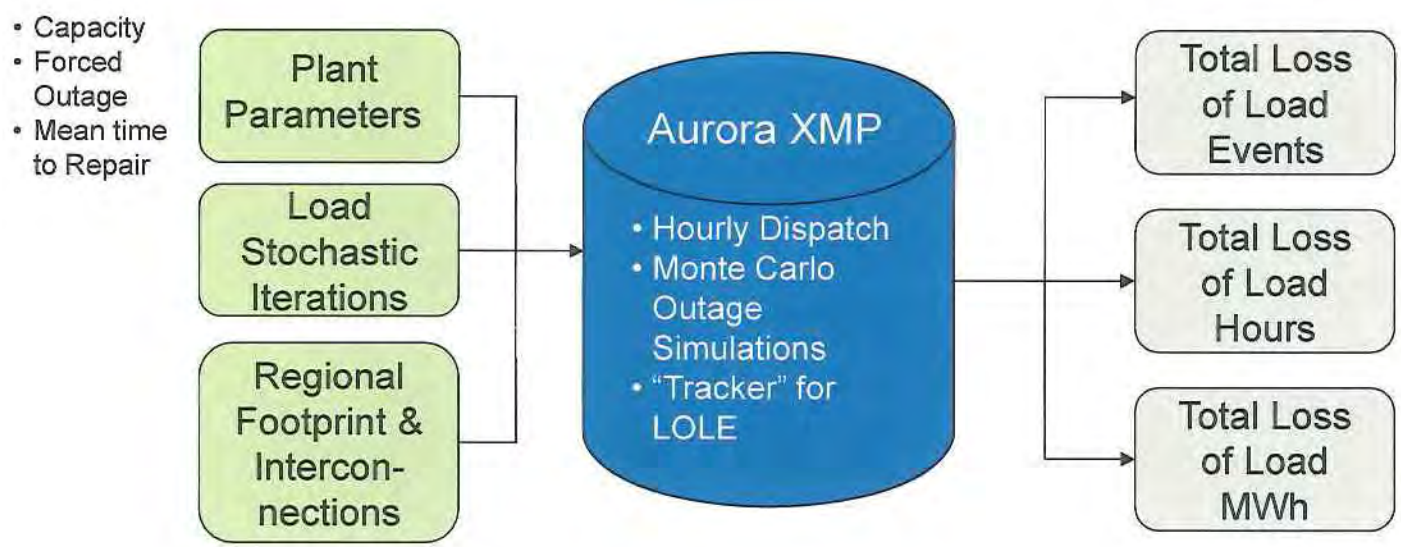
Answers for infrastructure and cities.

Loss of Load Study Assesses System Reliability

- Tests the likelihood that GWP's generation and transmission system will be unable to meet load for any period of time.
  - Monte Carlo-based simulations for outages in the generation and transmission system, as well as uncertainty in hourly loads for GWP's system.
- The industry standard for loss of load events ("LOLE") is one event in ten years ("1-in-10 Standard").



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Key Input Drivers Include Supply Availability and Load Uncertainty

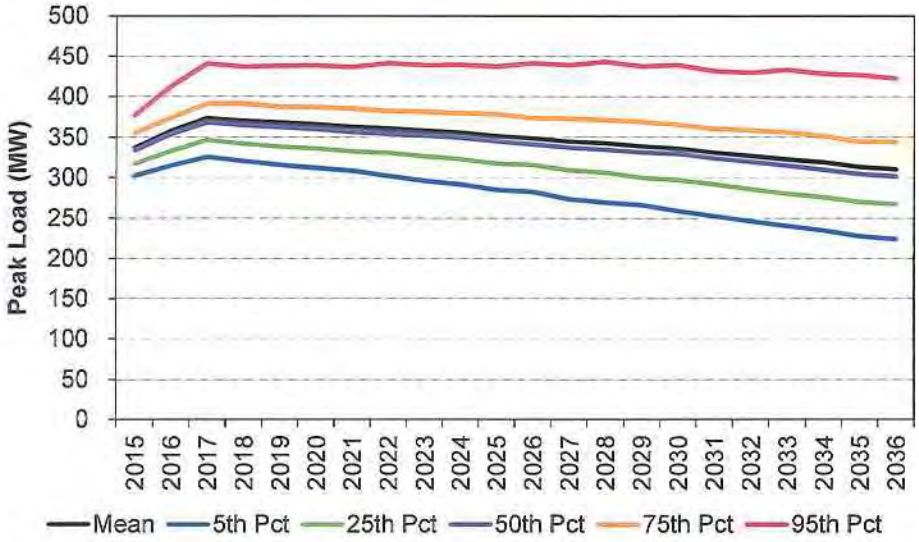
- Simulation evaluates possibility of generation or transmission system outage against a range of potential future load outcomes, driven by uncertainty in weather, economic growth, customer additions and energy efficiency penetration

Supply

System Element	Forced Outage Rate (%)	Mean Time to Repair (hours)
Grayson Unit 3	20%*	720
Grayson Unit 4	10%**	720
Grayson Unit 5	10%^	720
Grayson Unit 8A	10%^^	720
Grayson Unit 8B	10%^^	720
Grayson Unit 9	2.5%	88
LM6000 Simple Cycle	1.9%	88
LM6000 Combined Cycle	2.7%	120
Victorville – LA Import Path	0.35%	72
NOB – Sylmar Import Path	0.35%	72
Magnolia Import Path	0.35%	72

*Initial rate is 20%. This increases by 5% per year until planned retirement in 2020.
**Initial rate is 10%. This increases linearly up to 20% until planned retirement in 2023.
^Note that this unit retires in 2017.
^^Initial rate is 10%. This increases linearly up to 20% until retirement in 2022.

Demand



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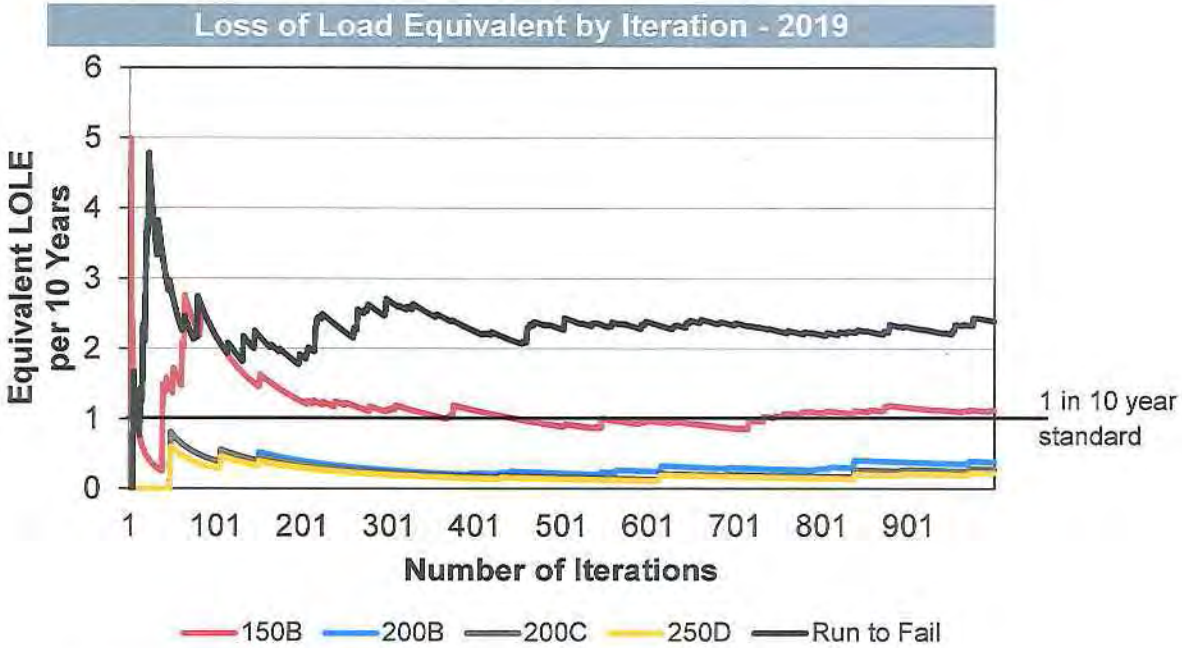
Run-to-Fail Portfolio Faces Significant Reliability Risk

- Under a 2019 test year, the run-to-fail and 150B options violate the standard
- By 2027, the run-to-fail portfolio faces significant risk of loss of load events, while the 150B portfolio moves back within acceptable standards as a result of declining load expectations



Portfolio/ Year	Loss of load Events per 10 years	Loss of Load Hours per 10 year period	Loss of MWh per 10 year period
150B/ 2019	1.1	5.3	186
200B/ 2019	0.4	1.5	55
200C/ 2019	0.3	1.2	45
250D/ 2019	0.2	0.9	28
Run to Fail/ 2019	2.4	14.3	569
150B/ 2027	0.5	2.0	55
Run to Fail/ 2027	22.3	149.8	5,962

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Cost Impacts of Loss of Load Events Can be Significant

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- The estimated value of lost load ("VOLL") climbs well into the millions of dollars per year range for the run-to-fail portfolio

Portfolio/ Year	Residential VOLL (2013$)	Industrial and Commercial VOLL (2013$)	VOLL (Total 2013$)
150B/ 2019	$6,075	$239,617-$835,982	$245,692-$842,057
200B/ 2019	$1,796	$70,854-$247,199	$72,650-$248,995
200C/ 2019	$1,470	$57,972-$202,254	$59,442-$203,724
250D/ 2019	$914	$36,071-$125,847	$36,985-$126,761
Run to Fail/ 2019	$18,583	$733,022-$2,557,385	$751,605-$2,575,968
150B/ 2027	$1,796	$70,854-$24,7199	$72,650-$248,995
Run to Fail/ 2027	$194,714	$7,680,626-$26,796,358	$7,875,340-$26,991,072

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Appendix V

Distributed Solar PV Penetration

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Answers for infrastructure and cities.

Impact of Distributed Solar PV on GWP Portfolio Costs

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Objective: Assess the likely future penetration rates of solar PV at the distributed (residential and commercial customers) level

Approach: Estimate market share and adoption rate as a function of economic payback period

- Retail rate projections for GWP customer classes
- California-specific capital cost estimates for solar PV
- Three discrete periods (early, mid, late) over which to evaluate payback economics

Outputs: Expected penetration over time, including:

- PV meter count
- Installed PV (MW)
- Reduction in total expected load (MWh) served by GWP

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Key Input Assumption Drivers

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- **Module Size**: 3 kW for residential customers; 8 kW for commercial customers. The module size was based on peak consumption per customer as observed historically. The solar module capacity factor was assumed to be 15%, consistent with average fixed tilt rooftop systems in California.
- **Technology Capital Costs**: Solar PV costs declining from $3,300/kW range to $2,600/kW by the end of the decade and $2,300/kW by 2030.
- **Retail Rate Projections**: The retail rates projection was based on current rates, incremental changes in revenue requirements over time as a function of changes in operating costs (fuel and operating costs) on the supply side, investments in generation such as Grayson, and investments in transmission and distribution expenses over time.

All values in real 2015$

Year	Retail Rate ($/KWh)	Capital Cost ($/KW)
2015	0.155	3,300
2016	0.165	3,169
2017	0.165	3,036
2018	0.163	2,905
2019	0.169	2,772
2020	0.176	2,641
2021	0.175	2,607
2022	0.177	2,574
2023	0.178	2,541
2024	0.178	2,508
2025	0.178	2,475
2026	0.178	2,443
2027	0.173	2,410
2028	0.170	2,376
2029	0.170	2,343
2030	0.170	2,310
2031	0.171	2,275
2032	0.172	2,238
2033	0.172	2,200
2034	0.172	2,160
2035	0.173	2,119

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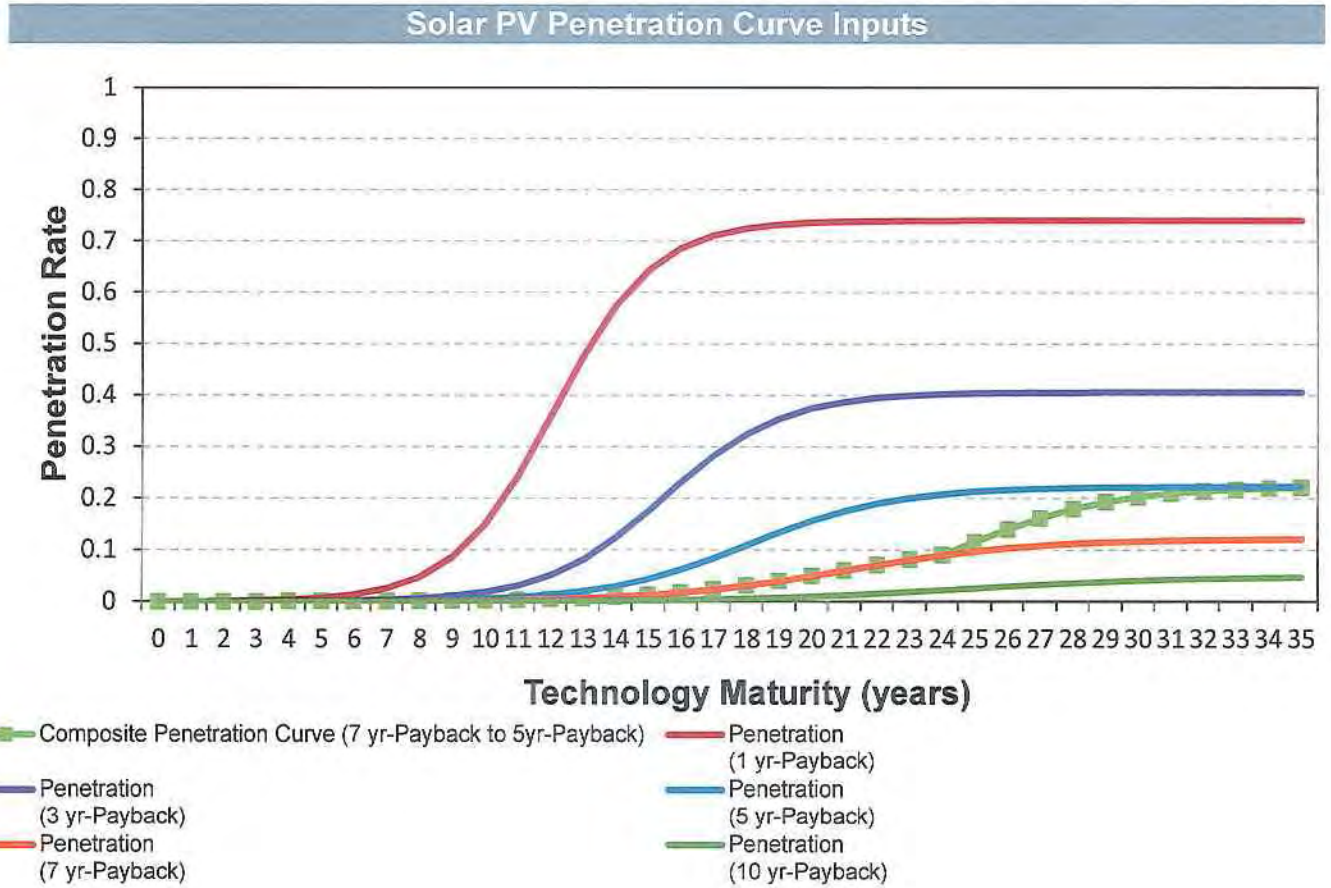
Solar Penetration Curves Vary across Different Economic Payback Periods



Source: NREL

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Total Load Reductions Could be as High as Five Percent by the 2030s

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- Reference case projections indicate potential sales declines on the order of five percent by 2030, with over 10,000 PV meters across GWP's service territory

Commercial Class Impacts

Commercial	Reduction In Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2015	611	412,369	0.1%	465	58
2016	849	439,043	0.2%	646	81
2017	1,168	462,520	0.3%	889	111
2018	1,589	460,321	0.3%	1209	151
2019	2,128	458,048	0.5%	1619	202
2020	2,794	455,541	0.6%	2127	266
2021	3,585	452,889	0.8%	2728	341
2022	4,476	450,175	1.0%	3406	426
2023	5,426	447,405	1.2%	4129	516
2024	6,379	444,577	1.4%	4855	607
2025	7,283	441,672	1.6%	5542	693
2026	8,092	438,715	1.8%	6158	770
2027	10,331	435,708	2.4%	7862	983
2028	12,546	432,639	2.9%	9548	1193
2029	14,536	429,498	3.4%	11062	1383
2030	16,175	426,284	3.8%	12310	1539
2031	17,441	423,028	4.1%	13273	1659

Residential Class Impacts

Residential	Reduction In Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2015	2,094	475,241	0.4%	1593	531
2016	2,910	493,548	0.6%	2215	738
2017	4,009	509,686	0.8%	3051	1017
2018	5,458	508,733	1.1%	4154	1385
2019	7,315	507,752	1.4%	5567	1856
2020	9,616	506,591	1.9%	7318	2439
2021	12,347	505,341	2.4%	9396	3132
2022	15,430	504,091	3.1%	11743	3914
2023	18,721	502,848	3.7%	14247	4749
2024	22,013	501,190	4.4%	16752	5584
2025	25,127	499,481	5.0%	19123	6374
2026	27,888	496,869	5.6%	21224	7075
2027	30,228	494,163	6.1%	23004	7668
2028	32,155	491,759	6.5%	24471	8157
2029	33,673	489,250	6.9%	25627	8542
2030	34,839	486,632	7.2%	26514	8838
2031	35,717	483,951	7.4%	27182	9061

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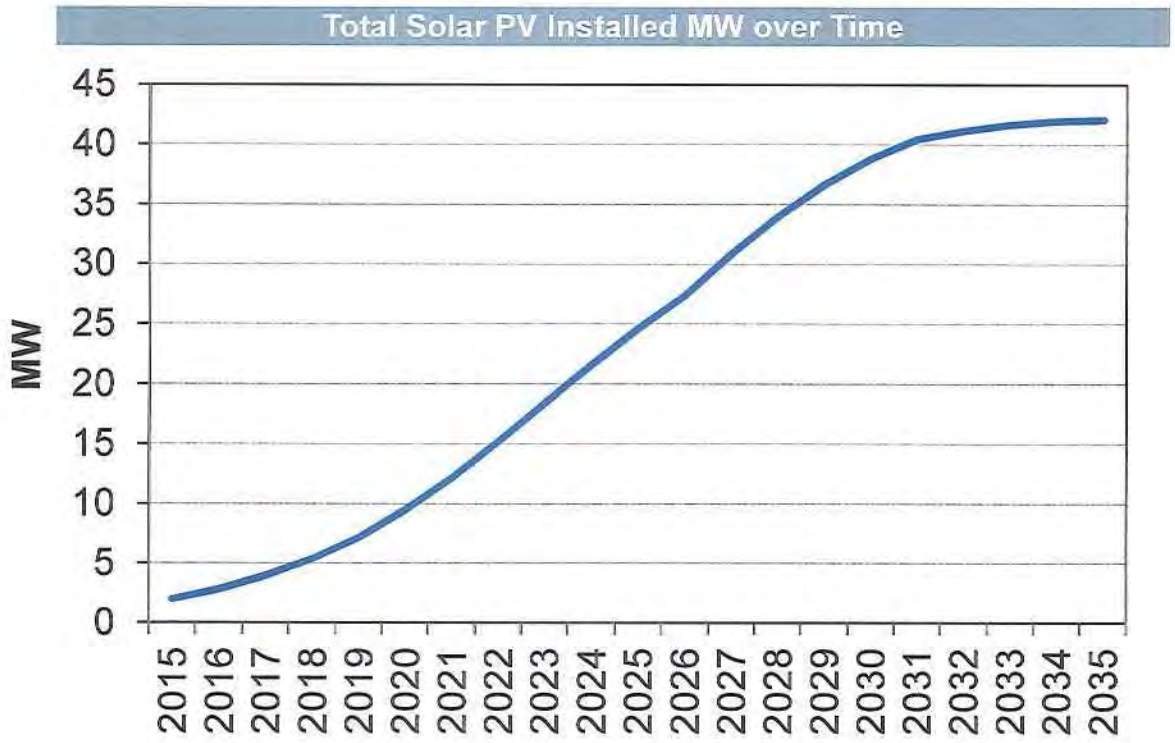
Total Distributed Solar PV Could Exceed 40 MW

- Reference case projections indicate close to 10 MW by the early 2020s and around 40 MW by the early 2030s
- <u>All portfolio analysis includes this capacity</u>



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Appendix VI

Load Forecast

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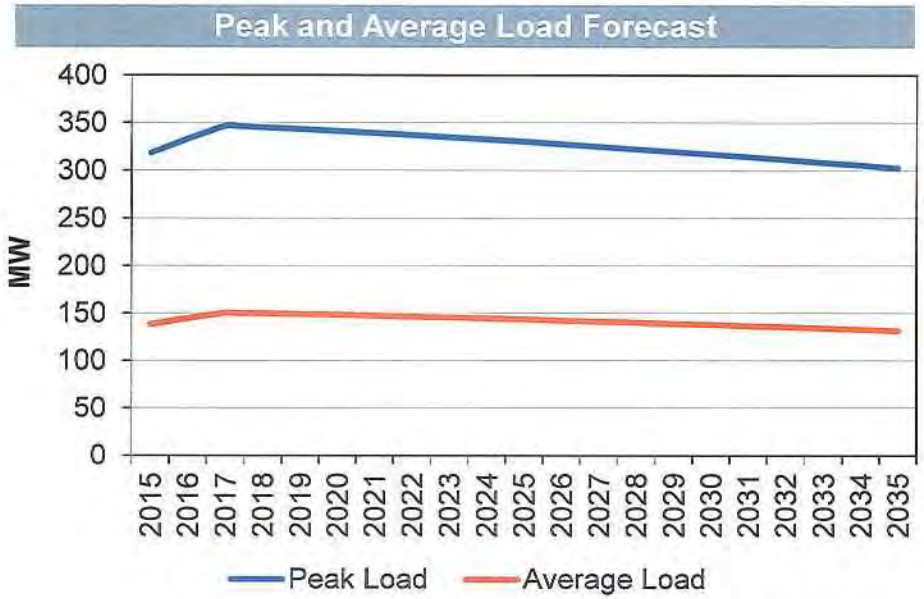
Answers for infrastructure and cities.

Load Forecast Overview

- Performed an historical econometric analysis of key weather and economic drivers;
- Developed the base load forecast driven by normal weather, projections for economic variables, and known customer additions;
- Made adjustments for energy efficiency, demand side management ("DSM"), and plug-in electric vehicle penetration.



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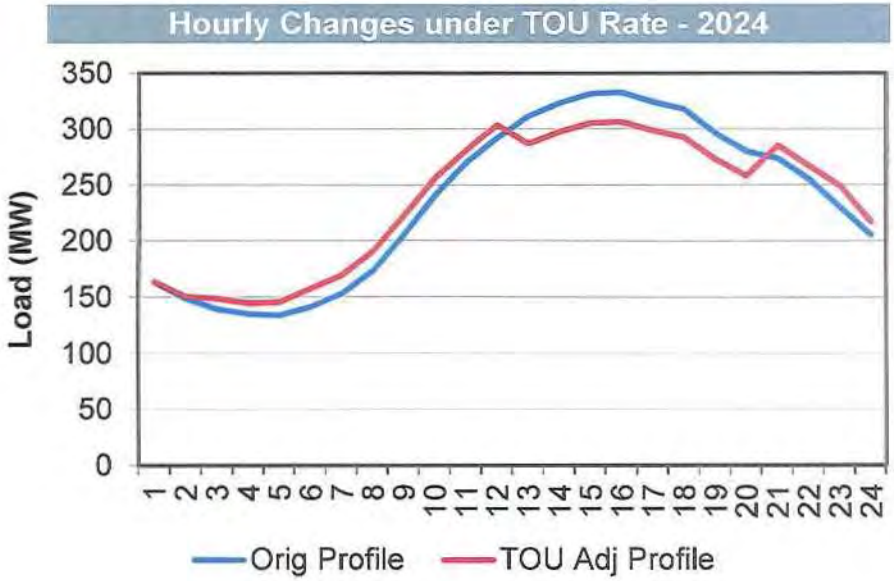
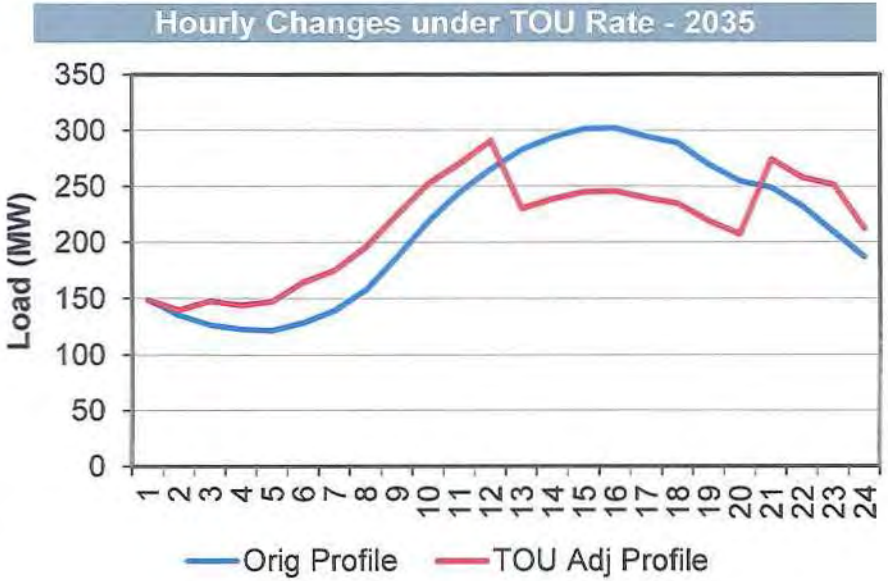
Time of Use Rates Can Drive Load Shifting

- As time passes and as more participants enter a TOU rate structure, load shifts are expected in GWP





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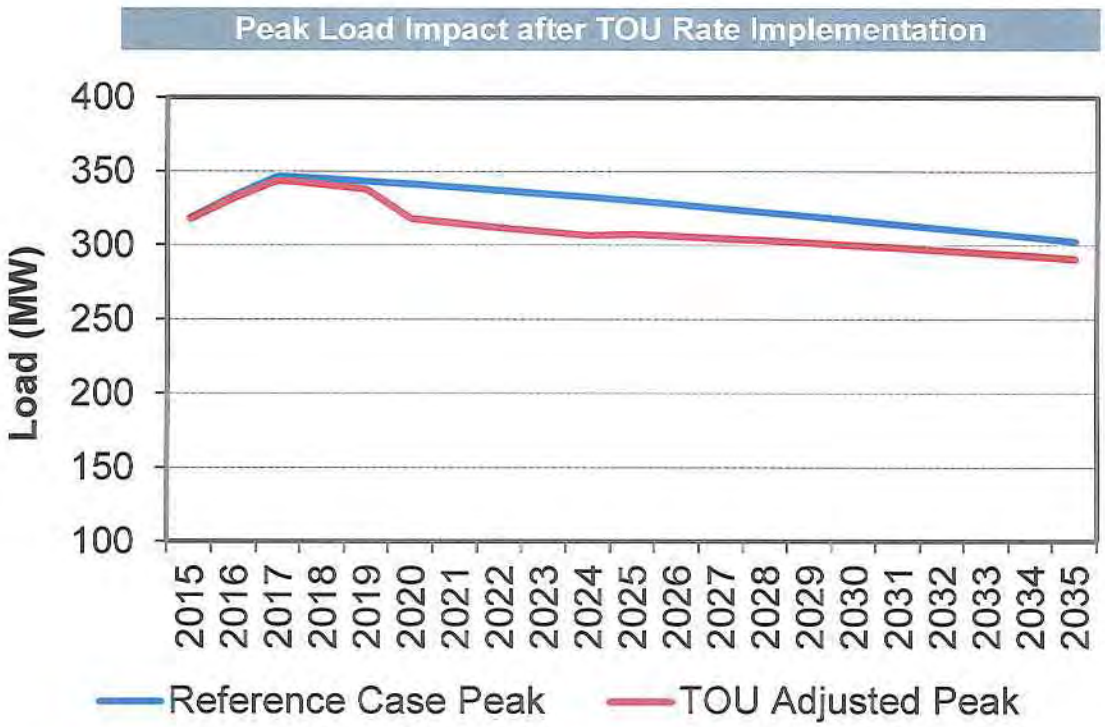
Time of Use Rates Can Lower Peak Load Expectations

- The implementation of a time of use rate program could shift significant load from the peak hours to other parts of the day if participation levels are high



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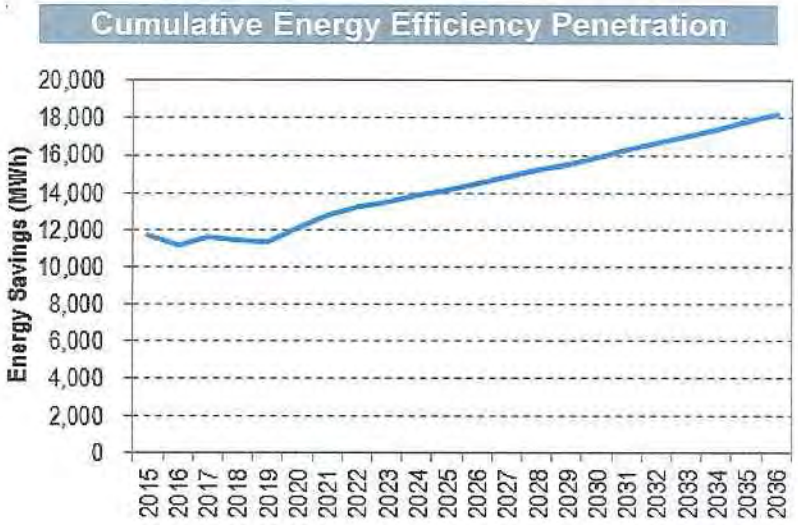
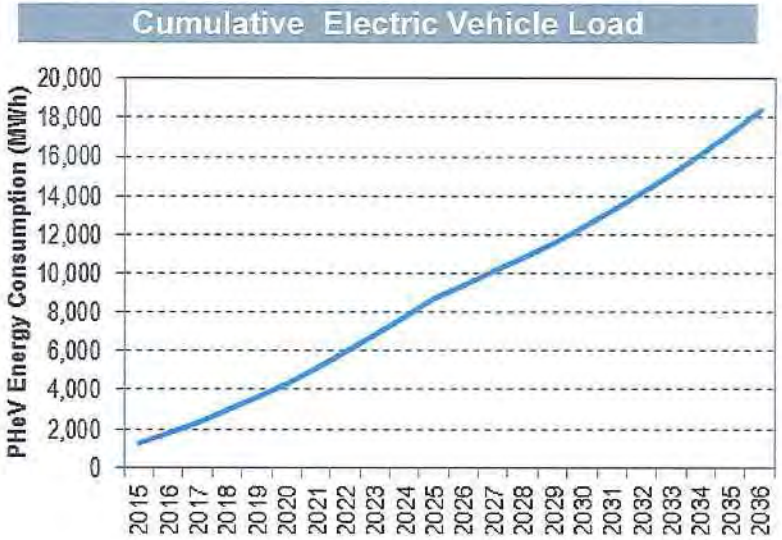
Load Forecast Assessed Energy Savings and Future Electric Vehicle Loads

- Load forecast analysis assessed energy efficiency penetration over time in line with GWP's current goals
- Load forecast included expectations for electric vehicle load growth in line with current state-level goals





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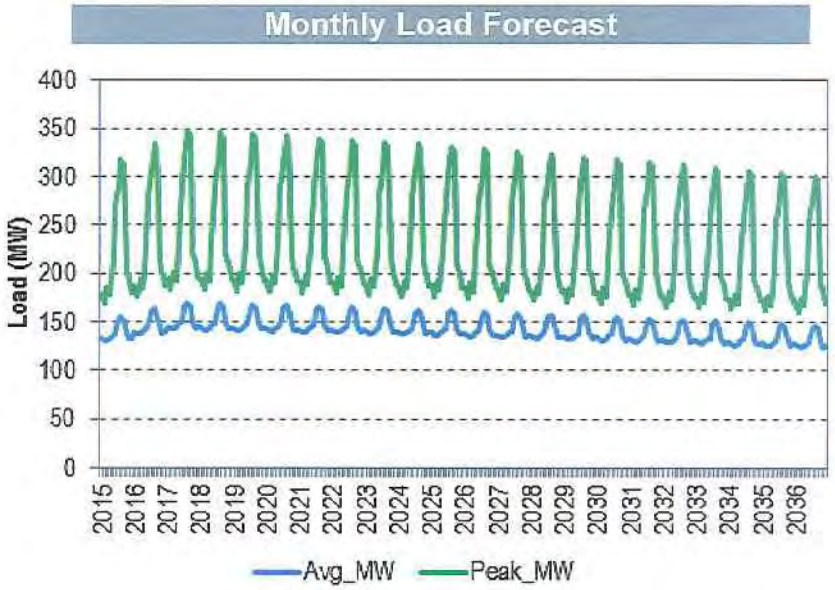
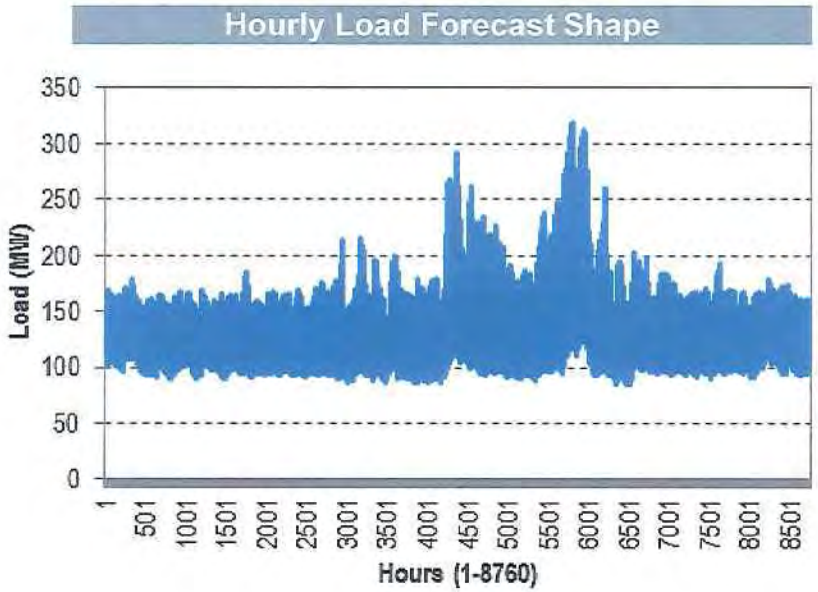
Detailed Hourly Portfolio Analysis Included Granular Projections





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FOOTNOTE 6

CITY OF GLENDALE, CALIFORNIA
Office of the City Attorney

613 East Broadway, Suite 220
Glendale, California 91206-4308
(818) 548-2080 Fax (818) 547-3402
www.glendaleca.gov

November 8, 2017

Via Electronic Mail to: ameszaros@earthjustice.org
Angela Johnson Meszaros
Earthjustice California Office
800 Wilshire Boulevard, Suite 1000
Los Angeles, California 90017

Re: Grayson Power Plant

Dear Ms. Meszaros:

I am writing in response to your October 31, 2017 email requesting further information related to the proposed Grayson Power Plant Repowering Project. You have requested:

(1) "Information that shows how GWP arrived at the $500 Million number—that is what's included in that budget estimate."
(2) The "load duration curves or other data that shows the variations in Grayson's load over time. We are particularly interested in understand the times of peak load throughout the year. We believe that this is information that would have been developed in order to understand the utilities' energy needs and also likely underlies the simplified chart that appears on page 2.8 of the Grayson DEIR."

The budget estimate for the Grayson Repowering Project is $500 Million. This includes the Engineer, Procure, Construct Contract, including procurement of balance of plant equipment; Owners Engineer Services, including preliminary design, plans, technical reports and specifications, environmental/CEQA review; permitting and procurement of emission credits; bidding, preliminary engineering, and procurement of Power Island Equipment; bidding and contract/services for the demolition of the existing facility; and project contingency. Please be advised that preliminary drafts, notes, or interagency or intra-agency memoranda are withheld pursuant to California Government Code §6254(a).

Information regarding load duration curves, peak loads throughout the year, and data underlying the chart on page 2.8 of the Grayson DEIR are included in the "BigMail" link within the email transmitting this letter. The chart on page 2.8 of the DEIR is based upon data from 2015, 2016 and January through September of 2017. Please also note that the abbreviation "HE" in the tables showing hourly information means "Hour Ending."

Should you have any questions regarding this information, please do not hesitate to contact me.

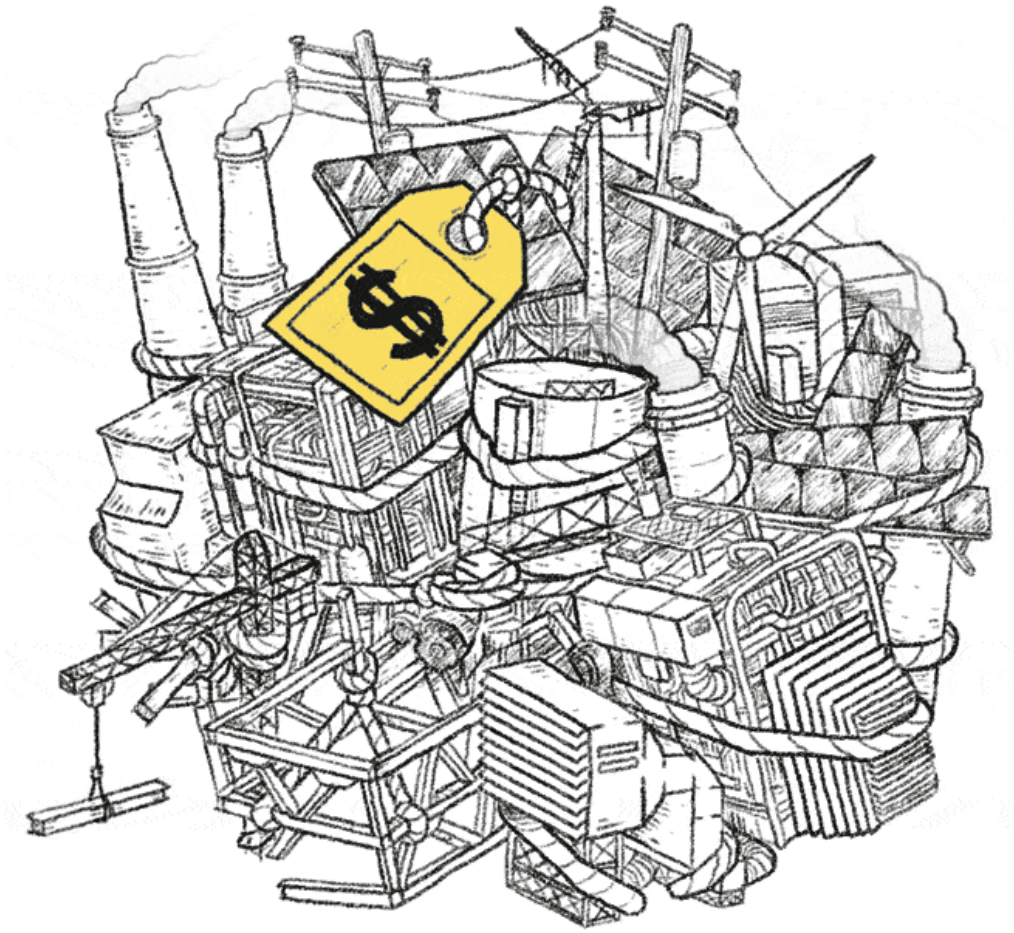
Very Truly Yours,
MICHAEL J. GARCIA, CITY ATTORNEY

By: Christine Godinez
Christine A. Godinez
Principal Assistant City Attorney

cc: Evan Gillespie (via electronic mail to: evan.gillespie@sierraclub.org)
Stephen M. Zurn, General Manager, GWP

WE RECYCLE

FOOTNOTE 19



Californians are paying billions for power they don't need

We're using less electricity. Some power plants have even shut down. So why do state officials keep approving new ones?

By IVAN PENN (HTTP://WWW.LATIMES.COM/LA-BIO-IVAN-PENN-STAFF.HTML) and RYAN MENEZES (HTTP://WWW.LATIMES.COM/LA-BIO-RYAN-MENEZES-STAFF.HTML) | Reporting from Yuba City, Calif.

FEB. 5, 2017

Read the story

View the graphic (/projects/la-fi-electricity-capacity-graphic/)

The bucolic orchards of Sutter County north of Sacramento had never seen anything like it: a visiting governor and a media swarm — all to christen the first major natural gas power plant in California in more than a decade.

At its 2001 launch, the Sutter Energy Center was hailed as the nation's cleanest power plant. It generated electricity while using less water and natural gas than older designs.

A year ago, however, the $300-million plant closed indefinitely, just 15 years into an expected 30- to 40-year lifespan. The power it produces is no longer needed — in large part because state regulators approved the construction of a plant just 40 miles away in Colusa that opened in 2010.

"We are building more power plants in California than ever before. Our goal is to make California energy self-sufficient." - Gov. Gray Davis at the opening of Sutter Energy Center in 2001. (Carolyn Cole / Los Angeles Times)

Sutter Energy Center has been offline since 2016, after just 15 years of an expected 30- to 40-year lifespan. (David Butow / For The Times)

Two other large and efficient power plants in California also are facing closure decades ahead of schedule. Like Sutter, there is little need for their electricity.

California has a big — and growing — glut of power, an investigation by the Los Angeles Times has found. The state's power plants are on track to be able to produce at least 21% more electricity than it needs by 2020, based on official estimates. And that doesn't even count the soaring production of electricity by rooftop solar panels that has added to the surplus.

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To cover the expense of new plants whose power isn't needed — Colusa, for example, has operated far below capacity since opening — Californians are paying a higher premium to switch on lights or turn on electric stoves. In recent years, the gap between what Californians pay versus the rest of the country has nearly doubled to about 50%.

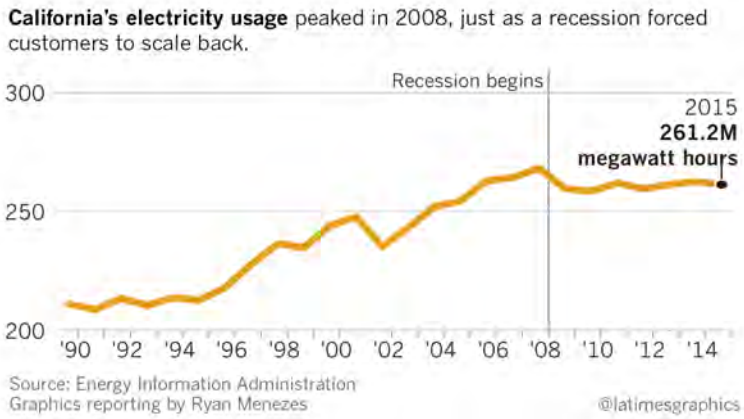
This translates into a staggering bill. Although California uses 2.6% less electricity annually from the power grid now than in 2008, residential and business customers together pay $6.8 billion more for power than they did then. The added cost to customers will total many billions of dollars over the next two decades, because regulators have approved higher rates for

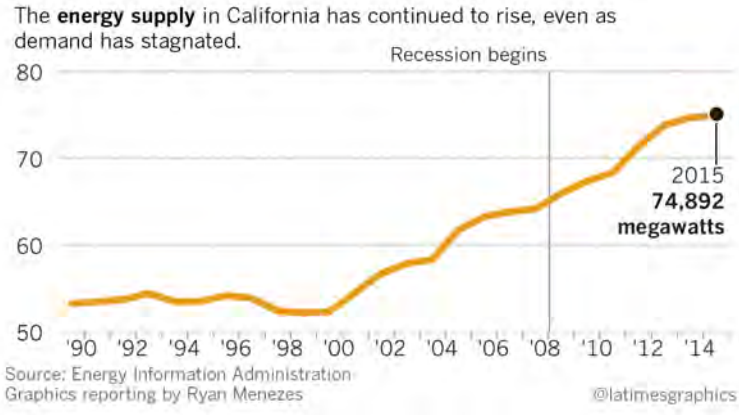
years to come so utilities can recoup the expense of building and maintaining the new plants, transmission lines and related equipment, even if their power isn't needed.

How this came about is a tale of what critics call misguided and inept decision-making by state utility regulators, who have ignored repeated warnings going back a decade about a looming power glut.

"In California, we're blinding ourselves to the facts," said Loretta Lynch, a former president of the California Public Utilities Commission, who along with consumer advocacy groups has fought to stop building plants. "We're awash in power at a premium price."

California regulators have for years allowed power companies to go on a building spree, vastly expanding the potential electricity supply in the state. Indeed, even as electricity demand has fallen since 2008, California's new plants have boosted its capacity enough to power all of the homes in a city the size of Los Angeles — six times over. Additional plants approved by regulators will begin producing more electricity in the next few years.





The missteps of regulators have been compounded by the self-interest of California utilities, Lynch and other critics contend. Utilities are typically guaranteed a rate of return of about 10.5% for the cost of each new plant regardless of need. This creates a major incentive to keep construction going: Utilities can make more money building new plants than by buying and reselling readily available electricity from existing plants run by competitors.

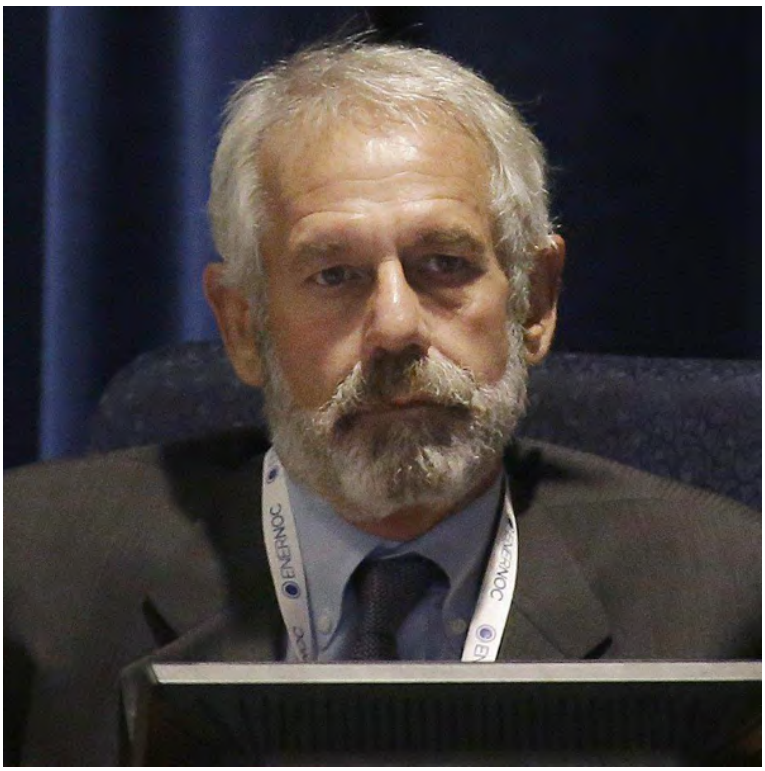
Regulators acknowledge the state has too much power but say they are being prudent. The investment, they maintain, is needed in case of an emergency — like a power plant going down unexpectedly, a heat wave blanketing the region or a wildfire taking down part of the transmission network.

"We overbuilt the system because that was the way we provided that degree of reliability," explained Michael Picker, president of the California Public Utilities Commission. "Redundancy is important to reliability."

Some of the excess capacity, he noted, is in preparation for the retirement of older, inefficient power plants over the next several years. The state is building many new plants to try to meet California environmental standards requiring 50% clean energy by 2030, he said.

In addition, he said, some municipalities — such as the Los Angeles Department of Water and Power — want to maintain their own separate systems, which leads to inefficiencies and redundancies. “These are all issues that people are willing to pay for,” Picker said.

Critics agree that some excess capacity is needed. And, in fact, state regulations require a 15% cushion. California surpasses that mark and is on pace to exceed it by 6 percentage points in the next three years, according to the Western Electricity Coordinating Council, which tracks capacity and reliability. In the past, the group has estimated the surplus would be even higher.



Michael Picker, current president of California’s Public Utilities Commission, said the state’s excess power supply is a strategic decision to ensure reliability. Loretta Lynch, who held the same position from 2002 to 2005, has been a critic of overbuilding since she chaired the regulatory agency. (Associated Press)

Even the 15% goal is “pretty rich,” said Robert McCullough of Oregon-based McCullough Research, who has studied California’s excess electric capacity for both utilities and regulators. “Traditionally, 10% is just fine. Below 7% is white knuckle. We are a long way from white-knuckle time” in California.

Contrary to Picker’s assertion, critics say, customers aren’t aware that too much capacity means higher rates. “The winners are the energy companies,” Lynch said. “The losers are businesses and families.”

The over-abundance of electricity can be traced to poorly designed deregulation of the industry, which set the stage for blackouts during the energy crisis of 2000-2001.

Lawmakers opened the state's power business to competition in 1998, so individual utilities would no longer enjoy a monopoly on producing and selling electricity. The goal was to keep prices lower while ensuring adequate supply. Utilities and their customers were allowed to buy electricity from new, unregulated operators called independent power producers.

The law created a new exchange where electricity could be bought and sold, like other commodities such as oil or wheat.

Everyone would benefit. Or so the thinking went.

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In reality, instead of lowering electricity costs and spurring innovation, market manipulation by Enron Corp. and other energy traders helped send electricity prices soaring.

That put utilities in a bind, because they had sold virtually all their natural gas plants. No longer able to produce as much of their own electricity, they ran up huge debts buying power that customers needed. Blackouts spread across the state.

State leaders, regulators and the utilities vowed never to be in that position again, prompting an all-out push to build more plants, both utility-owned and independent.

"They were not going to allow another energy crisis due to a lack of generation," said Alex Makler, a senior vice president of Calpine, the independent power producer that owns the Sutter Energy plant not far from Sacramento.

But the landscape was starting to change. By the time new plants began generating electricity, usage had begun a decline, in part because of the economic slowdown caused by the recession but also because of greater energy efficiency.

The state went from having too little to having way too much power.

“California has this tradition of astonishingly bad decisions,” said McCullough, the energy consultant. “They build and charge the ratepayers. There’s nothing dishonest about it. There’s nothing complicated. It’s just bad planning.”

> California has this tradition of astonishingly bad decisions.
>
> — Robert McCullough, energy consultant

The saga of two plants — Sutter Energy and Colusa — helps explain in a microcosm how California came to have too much energy, and is paying a high price for it.

Sutter was built in 2001 by Houston-based Calpine, which owns 81 power plants in 18 states.

Sutter Energy Center, now closed, made money only if Calpine Corp. found customers for the plant's power. Other large, natural gas plants in the state also face early closures. (David Butow / For The Times)

Colusa Generating Station opened in 2010. Pacific Gas & Electric will charge ratepayers more than $700 million over the plant's lifespan, to cover its operating costs and the profit guaranteed to public utility companies. (Rich Pedroncelli / AP)

Independents like Calpine don’t have a captive audience of residential customers like regulated utilities do. Instead, they sell their electricity under contract or into the electricity market, and make money only if they

can find customers for their power.

Sutter had the capacity to produce enough electricity to power roughly 400,000 homes. Calpine operated Sutter at an average of 50% of capacity in its early years — enough to make a profit.

But then Pacific Gas & Electric Co., a regulated, investor-owned utility, came along with a proposal to build Colusa.

It was not long after a statewide heat wave, and PG&E argued in its 2007 request seeking PUC approval that it needed the ability to generate more power. Colusa — a plant almost identical in size and technology to Sutter — was the only large-scale project that could be finished quickly, PG&E said.

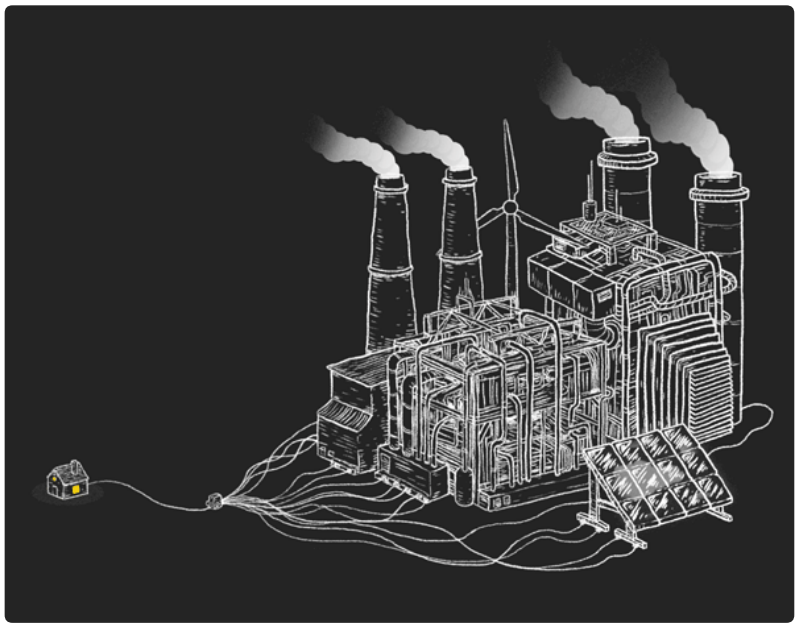
More than a half-dozen opponents, including representatives of independent power plants, a municipal utilities group and consumer advocates filed objections questioning the utility company. Wasn't there a more economical alternative? Did California need the plant at all?

They expressed concern that Colusa could be very expensive long-term for customers if it turned out that its power wasn't needed.

That's because public utilities such as PG&E operate on a different model.

If electricity sales don't cover the operating and construction costs of an independent power plant, it can't continue to run for long. And if the independent plant closes, the owner — and not ratepayers — bears the burden of the cost.

In contrast, publicly regulated utilities such as PG&E operate under more accommodating rules. Most of their revenue comes from electric rates approved by regulators that are set at a level to guarantee the utility recovers all costs for operating the electric system as well as the cost of building or buying a power plant — plus their guaranteed profit.



(/projects/la-fi-electricity-capacity-graphic/)
(/projects/la-fi-electricity-capacity-graphic/)
(/projects/la-fi-electricity-capacity-graphic/) California's energy supply: From blackouts to glut (/projects/la-fi-electricity-capacity-graphic/)

View the interactive graphic (/projects/la-fi-electricity-capacity-graphic/)

Protesters argued Colusa was unnecessary. The state's excess production capacity by 2010, the year Colusa was slated to come online, was projected to be almost 25% — 10 percentage points higher than state regulatory

requirements.

The looming oversupply, they asserted, meant that consumers would get stuck with much of the bill for Colusa no matter how little customers needed its electricity.

And the bill would be steep. Colusa would cost PG&E $673 million to build. To be paid off, the plant will have to operate until 2040. Over its lifetime, regulators calculated that PG&E will be allowed to charge more than $700 million to its customers to cover not just the construction cost but its operating costs and its profit.

Pacific Gas & Electric's Colusa Generating Station has operated at well below its generating capacity — just 47% in its first five years. (Rich Pedroncelli / AP)

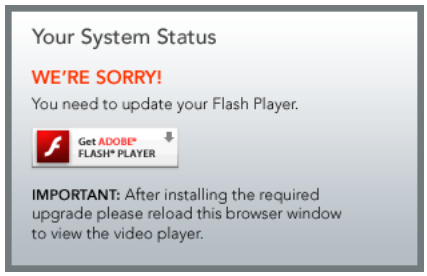
The urgent push by PG&E "seems unwarranted and inappropriate, and potentially costly to ratepayers," wrote Daniel Douglass, a lawyer for industry groups that represent independent power producers.

The California Municipal Utilities Assn. — whose members buy power from public utilities and then distribute that power to their customers — also complained in a filing that PG&E's application appeared to avoid the issue of how Colusa's cost would be shared if it ultimately sat idle. PG&E's "application is confusing and contradicting as to whether or not PG&E proposes to have the issue of stranded cost recovery addressed," wrote Scott Blaising, a lawyer representing the association. ("Stranded cost" is industry jargon for investment in an unneeded plant.)

The arguments over Colusa echoed warnings that had been made for years by Lynch, the former PUC commissioner.

A pro-consumer lawyer appointed PUC president in 2000 by Gov. Gray Davis, Lynch consistently argued as early as 2003 against building more power plants.

“I was like, ‘What the hell are we doing?’ ” recalled Lynch.



(http://www.adobe.com/go/getflash/)

She often butted heads with other commissioners and utilities who pushed for more plants and more reserves. Midway though her term, the governor replaced her as president — with a former utility company executive.

One key battle was fought over how much reserve capacity was needed to guard against blackouts. Lynch sought to limit excess capacity to 9% of the state’s electricity needs. But in January 2004, over her objections, the PUC approved a gradual increase to 15% by 2008.

“We’ve created an extraordinarily complex system that gives you a carrot at every turn,” Lynch said. “I’m a harsh critic because this is intentionally complex to make money on the ratepayer’s back.”

With Lynch no longer on the PUC, the commissioners voted 5-0 in June 2008 to let PG&E build Colusa. The rationale: The plant was needed, notwithstanding arguments that there was a surplus of electricity being produced in the market.

PG&E began churning out power at Colusa in 2010. For the nearby Sutter plant, that marked the beginning of the end as its electricity sales plummeted.

In the years that followed, Sutter’s production slumped to about a quarter of its capacity, or just half the rate it had operated previously.

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Calpine, Sutter's owner, tried to drum up new business for the troubled plant, reaching out to shareholder-owned utilities such as PG&E and other potential buyers. Calpine even proposed spending $100 million to increase plant efficiency and output, according to a letter the company sent to the PUC in February 2012.

PG&E rejected the offer, Calpine said, "notwithstanding that Sutter may have been able to provide a lower cost."

Asked for comment, PG&E said, "PG&E is dedicated to meeting the state's clean energy goals in cost-effective ways for our customers. We use competitive bidding and negotiations to keep the cost and risk for our customers as low as possible." It declined to comment further about its decision to build Colusa or on its discussions with Calpine.

Without new contracts and with energy use overall on the decline, Calpine had little choice but to close Sutter.

During a 2012 hearing about Sutter's distress, one PUC commissioner, Mike Florio, acknowledged that the plant's troubles were "just the tip of the proverbial iceberg." He added, "Put simply, for the foreseeable future, we have more power plants than we need."

Colusa, meanwhile, has operated at well below its generating capacity — just 47% in its first five years — much as its critics cautioned when PG&E sought approval to build it.

Sutter isn't alone. Other natural gas plants once heralded as the saviors of California's energy troubles have found themselves victims of the power glut. Independent power producers have announced plans to sell or close the 14-year-old Moss Landing power plant at Monterey Bay and the 13-year-old La Paloma facility in Kern County.

Put simply, for the foreseeable future, we have more power plants than we need.

— Mike Florio, former PUC commissioner

Robert Flexon, chief executive of independent power producer Dynegy Inc., which owns Moss Landing, said California energy policy makes it difficult for normal market competition. Independent plants are closing early, he said, because regulators favor utility companies over other power producers.

"It's not a game we can win," Flexon said.

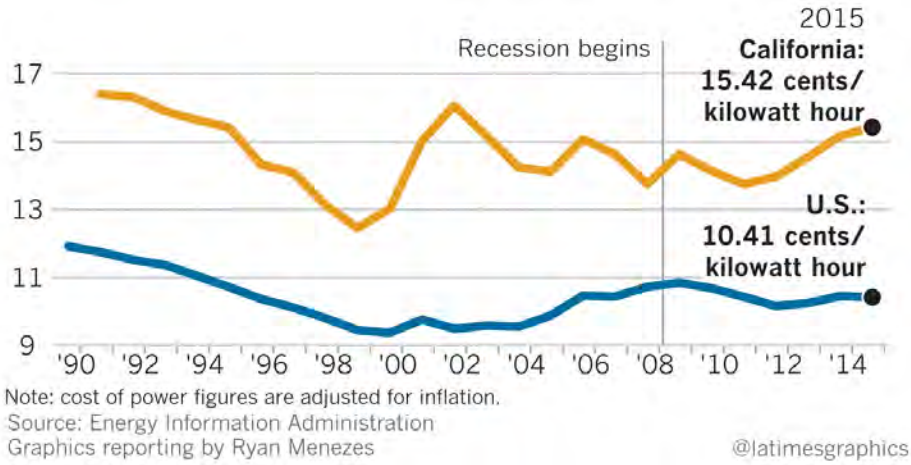
Since 2008 alone — when consumption began falling — about 30 new power plants approved by California regulators have started producing electricity. These plants account for the vast majority of the 17% increase in the potential electricity supply in the state during that period.

Hundreds of other small power plants, with production capacities too low to require the same level of review by state regulators, have opened as well.

Most of the big new plants that regulators approved also operate at below 50% of their generating capacity.

So that California utilities can foot the bill for these plants, the amount they are allowed by regulators to charge ratepayers has increased to $40 billion annually from $33.5 billion, according to data from the U.S. Energy Information Administration. This has tacked on an additional $60 a year to the average residential power bill, adjusted for inflation.

Another way of looking at the impact on consumers: The average cost of electricity in the state is now 15.42 cents a kilowatt hour versus 10.41 cents for users in the rest of the U.S. The rate in California, adjusted for inflation, has increased 12% since 2008, while prices have declined nearly 3% elsewhere in the country.



California utilities are “constantly crying wolf that we’re always short of power and have all this need,” said Bill Powers, a San Diego-based engineer and consumer advocate who has filed repeated objections with regulators to try to stop the approval of new plants. They are needlessly trying to attain a level of reliability that is a worst-case “act of God standard,” he said.

Even with the growing glut of electricity, consumer critics have found that it is difficult to block the PUC from approving new ones.

In 2010, regulators considered a request by PG&E to build a $1.15-billion power plant in Contra Costa County east of San Francisco, over objections that there wasn’t sufficient demand for its power. One skeptic was PUC commissioner Dian Grueneich. She warned that the plant wasn’t needed

and its construction would lead to higher electricity rates for consumers — on top of the 28% increase the PUC had allowed for PG&E over the previous five years.

The PUC was caught in a “time warp,” she argued, in approving new plants as electricity use fell. “Our obligation is to ensure that our decisions have a legitimate factual basis and that ratepayers’ interest are protected.”

Her protests were ignored. By a 4-to-1 vote, with Grueneich the lone dissenter, the commissioners approved the building of the plant.

Consumer advocates then went to court to stop the project, resulting in a rare victory against the PUC. In February 2014, the California Court of Appeals overturned the commission, ruling there was no evidence the plant was needed.

Recent efforts to get courts to block several other PUC-approved plants have failed, however, so the projects are moving forward.

(/projects/la-fi-electricity-capacity-graphic/)
California’s energy supply: From blackouts to glut (/projects/la-fi-electricity-capacity-graphic/)

View the interactive graphic (/projects/la-fi-electricity-capacity-graphic/)

Contact the reporters (mailto:ivan.penn@latimes.com; ryan.menezes@latimes.com?subject=The Power Boom) . For more coverage follow @ivanlpenn (https://twitter.com/ivanlpenn) and @ryanvmenezes (https://twitter.com/ryanvmenezes)

Times data editor Ben Welsh contributed to this report. Illustrations by Eben McCue. Graphics by Priya Krishnakumar and Paul Duginski. Produced by Lily Mihalik

More from the Los Angeles Times

FOOTNOTE 23

CITY OF GLENDALE, CALIFORNIA
Office of the City Attorney

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October 26, 2017

Via Electronic Mail to: ameszaros@earthjustice.org
Angela Johnson Meszaros
Earthjustice California Office
800 Wilshire Boulevard, Suite 1000
Los Angeles, California 90017

Re: Grayson Power Plant

Dear Ms. Meszaros:

This letter responds to your recent communications with Mr. Stephen Zurn, General Manager of Glendale Water & Power (GWP), requesting certain information regarding the Grayson Power Plant (Grayson). Specifically, you have requested:

(1) Information showing Grayson's usage during the past several years;
(2) Budget proposal for the construction of the Grayson Repowering Project; and
(3) Clarification regarding the single largest contingency requirements and the provisions at the balancing authority, state and/or federal level that establish Glendale's obligations.

With regard to Grayson's usage during the past several years, the table below illustrates Grayson's usage during the Years 2014, 2015 and 2016. Please note that the numbers in the table below (other than the percentages) are expressed in megawatt hours. Additionally, as you may know, auxiliary load refers to the power consumed onsite to operate the power plant. Grayson supplied 13.38% of load in 2014, 14.30% in 2015 and 12.58% in 2016:

		2014	2015	2016
Load	Glendale	1,169,667	1,146,225	1,114,209
Generation	Grayson Output	176,892	183,969	158,989
	Auxiliary Load	20,437	20,085	18,760
	Land Fill Gas	65,172	52,733	50,686
	Natural Gas	91,283	111,151	89,543
Percent of Load Served	Grayson Output (minus Aux)	13.38%	14.30%	12.59%
	Land Fill Gas	5.57%	4.60%	4.55%
	Natural Gas	7.80%	9.70%	8.04%

WE RECYCLE

The budget estimate for the Grayson Repowering Project is $500 Million. The estimate for the Engineer, Procure, Construct Contract is $175 Million to $225 Million. The City is in the process of preparing a cost of service analysis that will consider all GWP activities necessary to reliably deliver electricity within Glendale that are funded by rates, including capital projects such as the proposed Grayson Repowering. The development of a rate case is currently underway and estimated to be completed in February 2018.

With respect to the single largest contingency (also known as the "most severe single contingency") and balancing authority obligations, the applicable federal reliability standard is WECC Standard BAL-002-WECC-2a. This standard requires the Balancing Authority to maintain a minimum amount of contingency reserves. GWP operates as a metered subsystem within the LADWP Balancing Authority Area. As a metered subsystem, GWP must either self-provide or purchase from LADWP or others regulation and balancing services to balance the loads and resources within its metered subsystem (*i.e.* within GWP's service area). A copy of the City of Glendale's Balancing Authority Area Services Agreement with LADWP is enclosed. As for California's requirements, information regarding the State of California's Integrated Energy Policy Report requirements can be found at: http://www.energy.ca.gov/2017_energypolicy/ (see in particular 17-IEPR-02, entitled "Electricity Resource/ Supply Plans").

Should you have any questions regarding this information, please do not hesitate to contact me.

Very Truly Yours,
MICHAEL J. GARCIA, CITY ATTORNEY

By: _____
Christine A. Godinez
Principal Assistant City Attorney

cc: Evan Gillespie (via electronic mail to: evan.gillespie@sierraclub.org)
Stephen M. Zurn, General Manager, GWP

FOOTNOTE 27

STATE OF CALIFORNIA
AUTHENTICATED
ELECTRONIC LEGAL MATERIAL

Senate Bill No. 350

CHAPTER 547

An act to add Section 44258.5 to the Health and Safety Code, to amend Section 1720 of the Labor Code, to amend Sections 25310 and 25943 of, and to add Sections 25302.2 and 25327 to, the Public Resources Code, and to amend Sections 359, 399.4, 399.11, 399.12, 399.13, 399.15, 399.16, 399.18, 399.21, 399.30, 454.55, 454.56, 701.1, 740.8, 9505, and 9620 of, to amend and repeal Sections 337 and 352 of, to add Sections 237.5, 365.2, 366.3, 454.51, 454.52, 740.12, 9621, and 9622 to, to add Article 17 (commencing with Section 400) to Chapter 2.3 of Part 1 of Division 1 of, to add and repeal Article 5.5 (commencing with Section 359.5) of Chapter 2.3 of Part 1 of Division 1 of, and to repeal Article 5 (commencing with Section 359) of Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to energy.

[Approved by Governor October 7, 2015. Filed with
Secretary of State October 7, 2015.]

LEGISLATIVE COUNSEL'S DIGEST

SB 350, De León. Clean Energy and Pollution Reduction Act of 2015.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory jurisdiction over public utilities, including electrical corporations, community choice aggregators, and electric service providers, while local publicly owned electric utilities are under the direction of their governing boards. Existing law imposes various regulations on public utilities and local publicly owned electric utilities. Existing law establishes the California Renewables Portfolio Standards (RPS) Program, which is codified in the Public Utilities Act, with the target to increase the amount of electricity generated per year from eligible renewable energy resources to an amount that equals at least 33% of the total electricity sold to retail customers per year by December 31, 2020. Under existing law, a violation of the Public Utilities Act is a crime.

This bill would require that the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50% by December 31, 2030, as provided. The bill would make other revisions to the RPS Program and to certain other requirements on public utilities and publicly owned electric utilities.

Because certain of the above provisions are codified in the Public Utilities Act, this bill would impose a state-mandated local program by expanding the definition of a crime or establishing a new crime.

(2) Existing law requires the PUC to identify cost-effective electricity efficiency savings and establish efficiency targets for an electrical corporation to achieve, and to identify cost-effective natural gas efficiency

savings and establish efficiency targets for a gas corporation to achieve. Existing law requires a local publicly owned electric utility to identify all potential achievable cost-effective electricity efficiency savings and to establish annual targets for energy efficiency savings and demand reduction for the next 10-year period.

This bill would require the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The bill would require the PUC to establish efficiency targets for electrical and gas corporations consistent with this goal. The bill would require local publicly owned electric utilities to establish annual targets for energy efficiency savings and demand reduction consistent with this goal.

(3) The existing restructuring of the electrical industry within the Public Utilities Act provides for the establishment of the Independent System Operator (ISO) and requires the ISO to ensure efficient and reliable operation of the electrical transmission grid. Existing law prohibits the ISO from entering into a multistate entity or regional organization unless the ISO receives approval from the Electricity Oversight Board. Existing law states the intent of the Legislature to provide for the evolution of the ISO into a regional organization to promote the development of regional electricity transmission markets in the western states.

This bill would provide for the transformation of the ISO into a regional organization, with the approval of the Legislature, pursuant to a specified process.

(4) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

The people of the State of California do enact as follows:

SECTION 1. This act shall be known and may be cited as the Clean Energy and Pollution Reduction Act of 2015.

SEC. 2. (a) The Legislature finds and declares that the Governor has called for a new set of objectives in clean energy, clean air, and pollution reduction for 2030 and beyond. Those objectives include the following:

(1) To increase from 33 percent to 50 percent, the procurement of our electricity from renewable sources.

(2) To double the energy efficiency savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation.

(b) It is the intent of the Legislature in enacting this act to codify the targets described under subdivision (a) to ensure they are permanent, enforceable, and quantifiable.

SEC. 3. Section 44258.5 is added to the Health and Safety Code, to read:

44258.5. (a) For the purposes of this section, the following terms mean the following:

(1) "Local publicly owned electric utility" has the same meaning as defined in Section 224.3 of the Public Utilities Code.

(2) "Retail seller" has the same meaning as set forth in Section 399.12 of the Public Utilities Code.

(3) "Transportation electrification" has the same meaning as set forth in Section 237.5 of the Public Utilities Code.

(b) The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.

SEC. 4. Section 1720 of the Labor Code is amended to read:

1720. (a) As used in this chapter, "public works" means:

(1) Construction, alteration, demolition, installation, or repair work done under contract and paid for in whole or in part out of public funds, except work done directly by any public utility company pursuant to order of the Public Utilities Commission or other public authority. For purposes of this paragraph, "construction" includes work performed during the design and preconstruction phases of construction, including, but not limited to, inspection and land surveying work, and work performed during the postconstruction phases of construction, including, but not limited to, all cleanup work at the jobsite. For purposes of this paragraph, "installation" includes, but is not limited to, the assembly and disassembly of freestanding and affixed modular office systems.

(2) Work done for irrigation, utility, reclamation, and improvement districts, and other districts of this type. "Public work" does not include the operation of the irrigation or drainage system of any irrigation or reclamation district, except as used in Section 1778 relating to retaining wages.

(3) Street, sewer, or other improvement work done under the direction and supervision or by the authority of any officer or public body of the state, or of any political subdivision or district thereof, whether the political subdivision or district operates under a freeholder's charter or not.

(4) The laying of carpet done under a building lease-maintenance contract and paid for out of public funds.

(5) The laying of carpet in a public building done under contract and paid for in whole or in part out of public funds.

(6) Public transportation demonstration projects authorized pursuant to Section 143 of the Streets and Highways Code.

(7) (A) Infrastructure project grants from the California Advanced Services Fund pursuant to Section 281 of the Public Utilities Code.

(B) For purposes of this paragraph, the Public Utilities Commission is not the awarding body or the body awarding the contract, as defined in Section 1722.

(b) For purposes of this section, "paid for in whole or in part out of public funds" means all of the following:

(1) The payment of money or the equivalent of money by the state or political subdivision directly to or on behalf of the public works contractor, subcontractor, or developer.

(2) Performance of construction work by the state or political subdivision in execution of the project.

(3) Transfer by the state or political subdivision of an asset of value for less than fair market price.

(4) Fees, costs, rents, insurance or bond premiums, loans, interest rates, or other obligations that would normally be required in the execution of the contract, that are paid, reduced, charged at less than fair market value, waived, or forgiven by the state or political subdivision.

(5) Money loaned by the state or political subdivision that is to be repaid on a contingent basis.

(6) Credits that are applied by the state or political subdivision against repayment obligations to the state or political subdivision.

(c) Notwithstanding subdivision (b):

(1) Private residential projects built on private property are not subject to the requirements of this chapter unless the projects are built pursuant to an agreement with a state agency, redevelopment agency, or local public housing authority.

(2) If the state or a political subdivision requires a private developer to perform construction, alteration, demolition, installation, or repair work on a public work of improvement as a condition of regulatory approval of an otherwise private development project, and the state or political subdivision contributes no more money, or the equivalent of money, to the overall project than is required to perform this public improvement work, and the state or political subdivision maintains no proprietary interest in the overall project, then only the public improvement work shall thereby become subject to this chapter.

(3) If the state or a political subdivision reimburses a private developer for costs that would normally be borne by the public, or provides directly or indirectly a public subsidy to a private development project that is de minimis in the context of the project, an otherwise private development project shall not thereby become subject to the requirements of this chapter.

(4) The construction or rehabilitation of affordable housing units for low- or moderate-income persons pursuant to paragraph (5) or (7) of subdivision (e) of Section 33334.2 of the Health and Safety Code that are paid for solely with moneys from the Low and Moderate Income Housing Fund established pursuant to Section 33334.3 of the Health and Safety Code or that are paid for by a combination of private funds and funds available pursuant to Section 33334.2 or 33334.3 of the Health and Safety Code do not constitute a project that is paid for in whole or in part out of public funds.

(5) Unless otherwise required by a public funding program, the construction or rehabilitation of privately owned residential projects is not subject to the requirements of this chapter if one or more of the following conditions are met:

(A) The project is a self-help housing project in which no fewer than 500 hours of construction work associated with the homes are to be performed by the home buyers.

(B) The project consists of rehabilitation or expansion work associated with a facility operated on a not-for-profit basis as temporary or transitional housing for homeless persons with a total project cost of less than twenty-five thousand dollars ($25,000).

(C) Assistance is provided to a household as either mortgage assistance, downpayment assistance, or for the rehabilitation of a single-family home.

(D) The project consists of new construction, expansion, or rehabilitation work associated with a facility developed by a nonprofit organization to be operated on a not-for-profit basis to provide emergency or transitional shelter and ancillary services and assistance to homeless adults and children. The nonprofit organization operating the project shall provide, at no profit, not less than 50 percent of the total project cost from nonpublic sources, excluding real property that is transferred or leased. Total project cost includes the value of donated labor, materials, architectural, and engineering services.

(E) The public participation in the project that would otherwise meet the criteria of subdivision (b) is public funding in the form of below-market interest rate loans for a project in which occupancy of at least 40 percent of the units is restricted for at least 20 years, by deed or regulatory agreement, to individuals or families earning no more than 80 percent of the area median income.

(d) Notwithstanding any provision of this section to the contrary, the following projects shall not, solely by reason of this section, be subject to the requirements of this chapter:

(1) Qualified residential rental projects, as defined by Section 142(d) of the Internal Revenue Code, financed in whole or in part through the issuance of bonds that receive allocation of a portion of the state ceiling pursuant to Chapter 11.8 (commencing with Section 8869.80) of Division 1 of Title 2 of the Government Code on or before December 31, 2003.

(2) Single-family residential projects financed in whole or in part through the issuance of qualified mortgage revenue bonds or qualified veterans' mortgage bonds, as defined by Section 143 of the Internal Revenue Code, or with mortgage credit certificates under a Qualified Mortgage Credit Certificate Program, as defined by Section 25 of the Internal Revenue Code, that receive allocation of a portion of the state ceiling pursuant to Chapter 11.8 (commencing with Section 8869.80) of Division 1 of Title 2 of the Government Code on or before December 31, 2003.

(3) Low-income housing projects that are allocated federal or state low-income housing tax credits pursuant to Section 42 of the Internal Revenue Code, Chapter 3.6 (commencing with Section 50199.4) of Part 1

of Division 31 of the Health and Safety Code, or Section 12206, 17058, or 23610.5 of the Revenue and Taxation Code, on or before December 31, 2003.

(e) Notwithstanding paragraph (1) of subdivision (a), construction, alteration, demolition, installation, or repair work on the electric transmission system located in California constitutes a public works project for the purposes of this chapter.

(f) If a statute, other than this section, or a regulation, other than a regulation adopted pursuant to this section, or an ordinance or a contract applies this chapter to a project, the exclusions set forth in subdivision (d) do not apply to that project.

(g) For purposes of this section, references to the Internal Revenue Code mean the Internal Revenue Code of 1986, as amended, and include the corresponding predecessor sections of the Internal Revenue Code of 1954, as amended.

(h) The amendments made to this section by either Chapter 938 of the Statutes of 2001 or the act adding this subdivision shall not be construed to preempt local ordinances requiring the payment of prevailing wages on housing projects.

SEC. 5. Section 25302.2 is added to the Public Resources Code, to read:

25302.2. As part of the 2019 edition of the integrated energy policy report, the commission shall evaluate the actual energy efficiency savings, as defined in Section 25310, from negative therm interactive effects generated as a result of electricity efficiency improvements.

SEC. 6. Section 25310 of the Public Resources Code is amended to read:

25310. (a) For purposes of this section, the following terms have the following meanings:

(1) "End use" means the purpose for which energy is used, including, but not limited to, heating, cooling, or lighting, or class of energy uses upon which an energy efficiency program is focused, typically categorized by equipment purpose, equipment energy use intensity, or building type.

(2) "Energy efficiency savings" means reduced electricity or natural gas usage produced either by the installation of an energy efficiency measure or the adoption of an energy efficiency practice that maintains at least the same level of end-use service or by conservation actions that reduce energy use by reducing the quantity of baseline energy services demanded.

(b) On or before November 1, 2007, and by November 1 of every third year thereafter, the commission in consultation with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish targets for statewide annual energy efficiency savings and demand reduction for the next 10-year period. The commission shall base its estimate at least in part on information developed pursuant to Sections 454.55, 454.56, 715, 9505, 9615, and 9615.5 of the Public Utilities Code. The commission shall, for each electrical corporation and each gas corporation, include in the integrated energy policy report, a comparison of

the public utility's annual targets established pursuant to Sections 454.55 and 454.56, and the public utility's actual energy efficiency savings and demand reductions.

(c) (1) On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the midcase estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety.

(2) The commission may establish targets for the purposes of paragraph (1) that aggregate energy efficiency savings from both electricity and natural gas final end uses. Before establishing aggregate targets, the commission shall, in a public process that allows input from other stakeholders, adopt a methodology for aggregating electricity and natural gas final end-use energy efficiency savings in a consistent manner based on source of energy reduction and other relevant factors.

(3) In establishing the targets pursuant to paragraph (1), the commission shall assess the hourly and seasonal impact on statewide and local electricity demand.

(4) In assessing the feasibility and cost-effectiveness of energy efficiency savings for the purposes of paragraph (1), the commission and the Public Utilities Commission shall consider the results of energy efficiency potential studies that are not restricted by previous levels of utility energy efficiency savings.

(5) The energy efficiency savings and demand reduction reported for the purposes of achieving the targets established pursuant to paragraph (1) shall be measured taking into consideration the overall reduction in normalized metered electricity and natural gas consumption where these measurement techniques are feasible and cost effective.

(d) The targets established in subdivision (c) may be achieved through energy efficiency savings and demand reduction resulting from a variety of programs that include, but are not limited to, the following:

(1) Appliance and building energy efficiency standards developed and adopted pursuant to Section 25402.

(2) A comprehensive program to achieve greater energy efficiency savings in California's existing residential and nonresidential building stock pursuant to Section 25943.

(3) Programs funded and authorized pursuant to the California Clean Energy Job Creation Act (Division 16.3 (commencing with Section 26200)).

(4) Programs funded by the Greenhouse Gas Reduction Fund established pursuant to Section 16428.8 of the Government Code.

(5) Programs funded and authorized pursuant to this division.

(6) Programs of electrical or gas corporations, or community choice aggregators, that provide financial incentives, rebates, technical assistance, and support to their customers to increase energy efficiency, authorized by the Public Utilities Commission.

(7) Programs of local publicly owned electric utilities that provide financial incentives, rebates, technical assistance, and support to their customers to increase energy efficiency pursuant to Section 385 of the Public Utilities Code.

(8) Programs of electrical or gas corporations, local publicly owned electric utilities, or community choice aggregators, that achieve energy efficiency savings through operational, behavioral, and retrocommissioning activities.

(9) Programs that save energy in final end uses by reducing distribution feeder service voltage, known as conservation voltage reduction.

(10) Programs that save energy in final end uses by using cleaner fuels to reduce greenhouse gas emissions as measured on a lifecycle basis from the provision of energy services.

(11) Property Assessed Clean Energy (PACE) programs.

(e) Beginning with the 2019 edition of the integrated energy policy report and every two years thereafter, the commission shall provide recommendations and an update on progress toward achieving a doubling of energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030, pursuant to paragraph (1) of subdivision (c). The commission shall also include with the recommendations and update both of the following:

(1) An assessment of the effect of energy efficiency savings on electricity demand statewide, in local service territories, and on an hourly and seasonal basis.

(2) Specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

SEC. 7. Section 25327 is added to the Public Resources Code, to read:

25327. (a) The Legislature finds and declares all of the following:

(1) There is insufficient information available to fully realize the potential of solar photovoltaic energy generation to serve low-income customers, including those in disadvantaged communities.

(2) There is insufficient understanding of the barriers to access for low-income customers to all forms of renewable energy being generated in the state.

(3) There is insufficient understanding of the barriers to access for low-income customers to energy efficiency investments.

(4) There is insufficient understanding of the barriers to access for low-income customers to zero-emission and near-zero-emission transportation options.

(b) On or before January 1, 2017, the commission, with input from relevant state agencies and the public, shall conduct and complete a study on both of the following:

(1) Barriers to, and opportunities for, solar photovoltaic energy generation as well as barriers to, and opportunities for, access to other renewable energy by low-income customers.

(2) Barriers to contracting opportunities for local small businesses in disadvantaged communities.

(c) On or before January 1, 2017, the commission, with input from relevant state agencies and the public, shall develop and publish a study on barriers for low-income customers to energy efficiency and weatherization investments, including those in disadvantaged communities, as well as recommendations on how to increase access to energy efficiency and weatherization investments to low-income customers.

(d) On or before January 1, 2017, the State Air Resources Board, in consultation with the commission and with input from relevant state agencies and the public, shall develop and publish a study on barriers for low-income customers to zero-emission and near-zero-emission transportation options, including those in disadvantaged communities, as well as recommendations on how to increase access to zero-emission and near-zero-emission transportation options to low-income customers, including those in disadvantaged communities.

SEC. 8. Section 25943 of the Public Resources Code is amended to read:

25943. (a) (1) By March 1, 2010, the commission shall establish a regulatory proceeding to develop and implement a comprehensive program to achieve greater energy savings in California's existing residential and nonresidential building stock. This program shall comprise a complementary portfolio of techniques, applications, and practices that will achieve greater energy efficiency in existing residential and nonresidential structures that fall significantly below the current standards in Title 24 of the California Code of Regulations, as determined by the commission.

(2) The comprehensive program may include, but need not be limited to, a broad range of energy assessments, building benchmarking, energy rating, cost-effective energy efficiency improvements, public and private sector energy efficiency financing options, public outreach and education efforts, and green workforce training.

(3) The commission shall adopt, implement, and enforce a responsible contractor policy for use across all ratepayer-funded energy efficiency programs that involve installation or maintenance, or both installation and maintenance, by building contractors to ensure that retrofits meet high-quality performance standards and reduce energy savings lost or foregone due to poor-quality workmanship.

(4) The commission, in consultation with the Public Utilities Commission, shall establish consumer protection guidelines for energy efficiency products and services.

(b) To develop and implement the program specified in subdivision (a), the commission shall do both of the following:

(1) Coordinate with the Public Utilities Commission and consult with representatives from the Bureau of Real Estate, the Department of Housing and Community Development, investor-owned and publicly owned utilities, local governments, real estate licensees, commercial and homebuilders, commercial property owners, small businesses, mortgage lenders, financial institutions, home appraisers, inspectors, energy rating organizations, consumer groups, environmental and environmental justice groups, and other entities the commission deems appropriate.

(2) Hold at least three public hearings in geographically diverse locations throughout the state.

(c) In developing the requirements for the program specified in subdivision (a), the commission shall consider all of the following:

(1) The amount of annual and peak energy savings, greenhouse gas emission reductions, and projected customer utility bill savings that will accrue from the program.

(2) The most cost-effective means and reasonable timeframes to achieve the goals of the program.

(3) The various climatic zones within the state.

(4) An appropriate method to inform and educate the public about the need for, benefits of, and environmental impacts of, the comprehensive energy efficiency program.

(5) The most effective way to report the energy assessment results and the corresponding energy efficiency improvements to the owner of the residential or nonresidential building, including, among other things, the following:

(A) Prioritizing the identified energy efficiency improvements.

(B) The payback period or cost-effectiveness of each improvement identified.

(C) The various incentives, loans, grants, and rebates offered to finance the improvements.

(D) Available financing options including all of the following:

(i) Mortgages or sales agreement components.

(ii) On-bill financing.

(iii) Contractual property tax assessments.

(iv) Home warranties.

(6) Existing statutory and regulatory requirements to achieve energy efficiency savings and greenhouse gas emission reductions.

(7) A broad range of implementation approaches, including both utility and nonutility administration of energy efficiency programs, especially the use of not-for-profit and community-based organizations that assist with deployment in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

(8) Workforce development and job training for residents in disadvantaged communities, including veterans, at-risk youth, and members of the state and local community conservation corps.

(9) Any other considerations deemed appropriate by the commission.

(d) The program developed pursuant to this section shall do all of the following:

(1) Minimize the overall costs of establishing and implementing the comprehensive energy efficiency program requirements.

(2) Ensure, for residential buildings, that the energy efficiency assessments, ratings, or improvements do not unreasonably or unnecessarily affect the home purchasing process or the ability of individuals to rent housing. A transfer of property subject to the program implemented pursuant to this section shall not be invalidated solely because of the failure of a person to comply with a provision of the program.

(3) Ensure, for nonresidential buildings, that the energy improvements do not have an undue economic impact on California businesses.

(4) Determine, for residential buildings, the appropriateness of the Home Energy Rating System (HERS) program to support the goals of this section and whether there are a sufficient number of HERS-certified raters available to meet the program requirements.

(5) Determine, for nonresidential structures, the availability of an appropriate cost-effective energy efficiency assessment system and whether there are a sufficient number of certified raters or auditors available to meet the program requirements.

(6) Coordinate with the California Workforce Investment Board, the Employment Training Panel, the California Community Colleges, and other entities to ensure a qualified, well-trained workforce is available to implement the program requirements.

(7) Promote greater project penetration in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code, including the deployment of energy efficiency surveys and audits, energy efficiency retrofits and upgrades, weatherization, and followup project inspections by state-certified community conservation corps and other community-based workforce development organizations that serve residents of disadvantaged communities, including veterans and disadvantaged youth.

(8) Coordinate with, and avoid duplication of, existing proceedings of the Public Utilities Commission and programs administered by utilities.

(e) A home energy rating or energy assessment service does not meet the requirements of this section unless the service has been certified by the commission to be in compliance with the program criteria developed pursuant to this section and is in conformity with other applicable elements of the program.

(f) (1) The commission shall periodically update the criteria and adopt any revision that, in its judgment, is necessary to improve or refine program requirements after receiving public input.

(2) On or before January 1, 2017, and at least once every three years thereafter, the commission shall adopt an update to the program in furtherance of achieving a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030.

(g) Before implementing an element of the program developed pursuant to subdivision (a) that requires the expansion of statutory authority of the commission or the Public Utilities Commission, the commission and the Public Utilities Commission shall obtain legislative approval for the expansion of their authorities.

(h) The commission shall report on the status of the program in the integrated energy policy report pursuant to Section 25302.

(i) The commission shall fund activities undertaken pursuant to this section from the Federal Trust Fund consistent with the federal American Recovery and Reinvestment Act of 2009 (Public Law 111-5) or other sources of nonstate funds available to the commission for the purposes of this section.

(j) For purposes of this section, the following terms mean the following:

(1) "Energy assessment" means a determination of an energy user's energy consumption level, relative efficiency compared to other users, and opportunities to achieve greater efficiency or improve energy resource utilization.

(2) "Energy efficiency" means delivering equal or more services with less energy input from an energy source.

SEC. 9. Section 237.5 is added to the Public Utilities Code, to read:

237.5. "Transportation electrification" means the use of electricity from external sources of electrical power, including the electrical grid, for all or part of vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and greenhouse gases and the related programs and charging and propulsion infrastructure investments to enable and encourage this use of electricity.

SEC. 10. Section 337 of the Public Utilities Code is amended to read:

337. (a) The Independent System Operator governing board shall be composed of a five-member independent governing board of directors appointed by the Governor and subject to confirmation by the Senate. Any reference in this chapter or in any other provision of law to the Independent System Operator governing board means the independent governing board appointed under this subdivision.

(b) A member of the independent governing board appointed under subdivision (a) may not be affiliated with any actual or potential participant in any market administered by the Independent System Operator.

(c) (1) All appointments shall be for three-year terms.

(2) There is no limit on the number of terms that may be served by any member.

(d) The Oversight Board shall require the articles of incorporation and bylaws of the Independent System Operator to be revised in accordance with this section, and shall make filings with the Federal Energy Regulatory Commission as the Oversight Board determines to be necessary.

(e) For the purposes of the initial appointments to the Independent System Operator governing board, as provided in subdivision (a), the Governor shall appoint one member to a one-year term, two members to a two-year term, and two members to a three-year term.

(f) This section becomes inoperative on the date on which the governance modifications set forth in Section 359.5 become effective and is repealed on January 1 of the following year.

SEC. 11. Section 352 of the Public Utilities Code is amended to read:

352. (a) The Independent System Operator may not enter into a multistate entity or a regional organization as authorized in Section 359 unless that entry is approved by the Oversight Board.

(b) This section becomes inoperative on the date on which the governance modifications set forth in Section 359.5 become effective and is repealed on January 1 of the following year.

SEC. 12. Section 359 of the Public Utilities Code is amended to read:

359. (a) It is the intent of the Legislature to provide for the evolution of the Independent System Operator into a regional organization to promote the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the Independent System Operator to those markets.

(b) The preferred means by which the voluntary evolution described in subdivision (a) should occur is through the adoption of a regional compact or other comparable agreement among cooperating party states, the retail customers of which states would reside within the geographic territories served by the Independent System Operator.

(c) The agreement described in subdivision (b) should provide for all of the following:

(1) An equitable process for the appointment or confirmation by party states of members of the governing boards of the Independent System Operator.

(2) A respecification of the size, structure, representation, eligible membership, nominating procedures, and member terms of service of the governing boards of the Independent System Operator.

(3) Mechanisms by which each party state, jointly or separately, can oversee effectively the actions of the Independent System Operator as those actions relate to the assurance of electricity system reliability within the party state and to matters that affect electricity sales to the retail customers of the party state or otherwise affect the general welfare of the electricity consumers and the general public of the party state.

(4) The adherence by publicly owned and investor-owned utilities located in party states to enforceable standards and protocols to protect the reliability of the interconnected regional transmission and distribution systems.

(d) (1) Except for paragraphs (2) and (3), this section becomes inoperative on January 1, 2016.

(2) This section becomes operative on January 1, 2019, if Article 5.5 (commencing with Section 359.5) becomes inoperative on that date.

(3) If the governance modifications set forth in Section 359.5 become effective, this article is repealed on January 1 of the year following the effective date of the governance modifications.

SEC. 13. Article 5.5 (commencing with Section 359.5) is added to Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, to read:

Article 5.5. Transformation of the Independent System Operator

359.5. (a) It is the intent of the Legislature to provide for the transformation of the Independent System Operator into a regional organization to promote the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the Independent System Operator to those markets, and that the transformation should only occur where it is in the best interests of California and its ratepayers.

(b) The transformation of the Independent System Operator into a regional organization shall not alter its obligations to the state or to electricity consumers within the state or its obligations to comply with state laws. The Independent System Operator shall retain its obligations set forth in Section 345.5, shall maintain the standards for open meetings and public access to corporate records as set forth in Section 345.5, and shall facilitate effective tracking and reporting mechanisms in support of state enforcement of Division 25.5 (commencing with Section 38500) of the Health and Safety Code.

(c) The voluntary transformation described in subdivision (a) shall occur through additional transmission owners joining the Independent System Operator with approval from their own state or local regulatory authorities, as applicable.

(d) Modifications to the Independent System Operator governance structure, through changes to its bylaws or other corporate governance documents, would be needed to allow this transformation.

(e) The Independent System Operator shall prepare the governance modifications needed as described in subdivision (d), but they shall not become effective until all of the following occur:

(1) The Independent System Operator conducts one or more studies of the impacts of a regional market enabled by the proposed governance modifications, including overall benefits to ratepayers, including the creation or retention of jobs and other benefits to the California economy, environmental impacts in California and elsewhere, impacts in disadvantaged communities, emissions of greenhouse gases and other air pollutants, and reliability and integration of renewable energy resources. The modeling, including all assumptions underlying the modeling, shall be made available for public review.

(2) The commission, Energy Commission, and State Air Resources Board jointly hold at least one public workshop where the Independent System Operator presents the proposed governance modifications and the results of the studies described in paragraph (1). The related Independent System Operator documents shall be made public before the workshop.

(3) The Independent System Operator submits to the Governor the studies described in paragraph (1) and revised bylaws or other corporate governance documents setting forth the proposed modifications to its governance structure.

(4) The Governor transmits to the Legislature the studies described in paragraph (1) and revised bylaws or other corporate governance documents setting forth the proposed modifications to its governance structure, no later than December 31, 2017.

(5) The Legislature enacts a statute implementing the revised governance changes.

(f) The Independent System Operator shall expeditiously adopt the modifications to its governance structure enacted by the Legislature pursuant to paragraph (5) of subdivision (e) so that the modifications become effective before new transmission owners from outside California complete the process of joining the Independent System Operator.

(g) The revised governance structure shall not alter or abridge the contractual rights of a transmission owner to withdraw from participation in the Independent System Operator.

(h) One year after the seating of the new, revised governing board of the Independent System Operator pursuant to the modifications of its governance structure, and every two years thereafter, the Independent System Operator shall prepare a report to the states within the areas it serves documenting its furtherance of applicable state and federal laws and regulations affecting the electric industry.

(i) This article is repealed on January 1, 2019, if a statute implementing the governance modifications has not become effective on or before January 1, 2019.

SEC. 14. Section 365.2 is added to the Public Utilities Code, to read:

365.2. The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

SEC. 15. Section 366.3 is added to the Public Utilities Code, to read:

366.3. Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

SEC. 16. Section 399.4 of the Public Utilities Code is amended to read:

399.4. (a) (1) In order to ensure that prudent investments in energy efficiency continue to be made that produce cost-effective energy savings, reduce customer demand, and contribute to the safe and reliable operation of the electric distribution grid, it is the policy of this state and the intent of the Legislature that the commission shall continue to administer cost-effective energy efficiency programs authorized pursuant to existing statutory authority.

(2) As used in this section, the term "energy efficiency" includes, but is not limited to, cost-effective activities to achieve peak load reduction that

improve end-use efficiency, lower customers' bills, and reduce system needs.

(b) (1) Any rebates or incentives offered by a public utility for an energy efficiency improvement or installation of energy efficient components, equipment, or appliances in buildings shall be provided only if the recipient of the rebate or incentive certifies that the improvement or installation has complied with any applicable permitting requirements and, if a contractor performed the installation or improvement, that the contractor holds the appropriate license for the work performed.

(2) This subdivision does not imply or create authority or responsibility, or expand existing authority or responsibility, of a public utility for the enforcement of the building energy and water efficiency standards adopted pursuant to subdivision (a) or (b) of Section 25402 of the Public Resources Code, or appliance efficiency standards and certification requirements adopted pursuant to subdivision (c) of Section 25402 of the Public Resources Code.

(c) The commission, in evaluating energy efficiency investments under its existing statutory authority, shall also ensure that local and regional interests, multifamily dwellings, and energy service industry capabilities are incorporated into program portfolio design and that local governments, community-based organizations, and energy efficiency service providers are encouraged to participate in program implementation where appropriate.

(d) The commission, in a new or existing proceeding, shall review and update its policies governing energy efficiency programs funded by utility customers to facilitate achieving the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code. In updating its policies, the commission shall, at a minimum, do all of the following:

(1) Authorize market transformation programs with appropriate levels of funding to achieve deeper energy efficiency savings.

(2) Authorize pay for performance programs that link incentives directly to measured energy savings. As part of pay for performance programs authorized by the commission, customers should be reasonably compensated for developing and implementing an energy efficiency plan, with a portion of their incentive reserved pending post project measurement results.

(3) Authorize programs to achieve deeper savings through operational, behavioral, and retrocommissioning activities.

(4) Ensure that customers have certainty in the values and methodology used to determine energy efficiency incentives by basing the amount of any incentives provided by gas and electrical corporations on the values and methodology contained in the executed customer agreement. Incentive payments shall be based on measured results.

SEC. 17. Section 399.11 of the Public Utilities Code is amended to read:

399.11. The Legislature finds and declares all of the following:

(a) In order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2013, 33 percent by December 31, 2020, and 50 percent by December 31, 2030, it is the intent of the Legislature that the commission

and the Energy Commission implement the California Renewables Portfolio Standard Program described in this article.

(b) Achieving the renewables portfolio standard through the procurement of various electricity products from eligible renewable energy resources is intended to provide unique benefits to California, including all of the following, each of which independently justifies the program:

(1) Displacing fossil fuel consumption within the state.

(2) Adding new electrical generating facilities in the transmission network within the Western Electricity Coordinating Council service area.

(3) Reducing air pollution in the state.

(4) Meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation.

(5) Promoting stable retail rates for electric service.

(6) Meeting the state's need for a diversified and balanced energy generation portfolio.

(7) Assistance with meeting the state's resource adequacy requirements.

(8) Contributing to the safe and reliable operation of the electrical grid, including providing predictable electrical supply, voltage support, lower line losses, and congestion relief.

(9) Implementing the state's transmission and land use planning activities related to development of eligible renewable energy resources.

(c) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Resources Program administered by the Energy Commission and established pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code.

(d) New and modified electric transmission facilities may be necessary to facilitate the state achieving its renewables portfolio standard targets.

(e) (1) Supplying electricity to California end-use customers that is generated by eligible renewable energy resources is necessary to improve California's air quality and public health, and the commission shall ensure rates are just and reasonable, and are not significantly affected by the procurement requirements of this article. This electricity may be generated anywhere in the interconnected grid that includes many states, and areas of both Canada and Mexico.

(2) This article requires generating resources located outside of California that are able to supply that electricity to California end-use customers to be treated identically to generating resources located within the state, without discrimination.

(3) California electrical corporations have already executed, and the commission has approved, power purchase agreements with eligible renewable energy resources located outside of California that will supply electricity to California end-use customers. These resources will fully count toward meeting the renewables portfolio standard procurement requirements.

SEC. 18. Section 399.12 of the Public Utilities Code is amended to read:

399.12. For purposes of this article, the following terms have the following meanings:

(a) "Conduit hydroelectric facility" means a facility for the generation of electricity that uses only the hydroelectric potential of an existing pipe, ditch, flume, siphon, tunnel, canal, or other manmade conduit that is operated to distribute water for a beneficial use.

(b) "Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange generation balance within a balancing authority area, and supports interconnection frequency in real time.

(c) "Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of the area within which the balancing authority maintains the electrical load-resource balance.

(d) "California balancing authority" is a balancing authority with control over a balancing authority area primarily located in this state and operating for retail sellers and local publicly owned electric utilities subject to the requirements of this article and includes the Independent System Operator (ISO) and a local publicly owned electric utility operating a transmission grid that is not under the operational control of the ISO. A California balancing authority is responsible for the operation of the transmission grid within its metered boundaries which is not limited by the political boundaries of the State of California.

(e) "Eligible renewable energy resource" means an electrical generating facility that meets the definition of a "renewable electrical generation facility" in Section 25741 of the Public Resources Code, subject to the following:

(1) (A) An existing small hydroelectric generation facility of 30 megawatts or less shall be eligible only if a retail seller or local publicly owned electric utility procured the electricity from the facility as of December 31, 2005. A new hydroelectric facility that commences generation of electricity after December 31, 2005, is not an eligible renewable energy resource if it will cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.

(B) Notwithstanding subparagraph (A), a conduit hydroelectric facility of 30 megawatts or less that commenced operation before January 1, 2006, is an eligible renewable energy resource. A conduit hydroelectric facility of 30 megawatts or less that commences operation after December 31, 2005, is an eligible renewable energy resource so long as it does not cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.

(C) A facility approved by the governing board of a local publicly owned electric utility prior to June 1, 2010, for procurement to satisfy renewable energy procurement obligations adopted pursuant to former Section 387, shall be certified as an eligible renewable energy resource by the Energy Commission pursuant to this article, if the facility is a "renewable electrical generation facility" as defined in Section 25741 of the Public Resources Code.

(D) (i) A small hydroelectric generation unit with a nameplate capacity not exceeding 40 megawatts that is operated as part of a water supply or

conveyance system is an eligible renewable energy resource only for the retail seller or local publicly owned electric utility that procured the electricity from the unit as of December 31, 2005. No unit shall be eligible pursuant to this subparagraph if an application for certification is submitted to the Energy Commission after January 1, 2013. Only one retail seller or local publicly owned electric utility shall be deemed to have procured electricity from a given unit as of December 31, 2005.

(ii) Notwithstanding clause (i), a local publicly owned electric utility that meets the criteria of subdivision (j) of Section 399.30 may sell to another local publicly owned electric utility electricity from small hydroelectric generation units that qualify as eligible renewable energy resources under clause (i), and that electricity may be used by the local publicly owned electric utility that purchased the electricity to meet its renewables portfolio standard procurement requirements. The total of all those sales from the utility shall be no greater than 100,000 megawatthours of electricity.

(iii) The amendments made to this subdivision by the act adding this subparagraph are intended to clarify existing law and apply from December 10, 2011.

(2) (A) A facility engaged in the combustion of municipal solid waste shall not be considered an eligible renewable energy resource.

(B) Subparagraph (A) does not apply to contracts entered into before January 1, 2017, for the procurement of renewable energy resources from a facility located in Stanislaus County that was operational prior to September 26, 1996.

(f) "Procure" means to acquire through ownership or contract.

(g) "Procurement entity" means any person or corporation authorized by the commission to enter into contracts to procure eligible renewable energy resources on behalf of customers of a retail seller pursuant to subdivision (f) of Section 399.13.

(h) (1) "Renewable energy credit" means a certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.

(2) "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

(3) (A) Electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels, beyond a de minimis quantity used to generate electricity in the same process through which the facility converts renewable fuel to electricity, shall not result in the creation of a renewable energy credit. The Energy Commission shall set the de minimis quantity of nonrenewable fuels for each renewable energy technology at a level of no more than 2 percent of the total quantity of fuel used by the

technology to generate electricity. The Energy Commission may adjust the de minimis quantity for an individual facility, up to a maximum of 5 percent, if it finds that all of the following conditions are met:

(i) The facility demonstrates that the higher quantity of nonrenewable fuel will lead to an increase in generation from the eligible renewable energy facility that is significantly greater than generation from the nonrenewable fuel alone.

(ii) The facility demonstrates that the higher quantity of nonrenewable fuels will reduce the variability of its electrical output in a manner that results in net environmental benefits to the state.

(iii) The higher quantity of nonrenewable fuel is limited to either natural gas or hydrogen derived by reformation of a fossil fuel.

(B) Electricity generated by a small hydroelectric generation facility shall not result in the creation of a renewable energy credit unless the facility meets the requirements of subparagraph (A) or (D) of paragraph (1) of subdivision (e).

(C) Electricity generated by a conduit hydroelectric generation facility shall not result in the creation of a renewable energy credit unless the facility meets the requirements of subparagraph (B) of paragraph (1) of subdivision (e).

(D) Electricity generated by a facility engaged in the combustion of municipal solid waste shall not result in the creation of a renewable energy credit. This subparagraph does not apply to renewable energy credits that were generated before January 1, 2017, by a facility engaged in the combustion of municipal solid waste located in Stanislaus County that was operational prior to September 26, 1996, and sold pursuant to contacts entered into before January 1, 2017.

(i) "Renewables portfolio standard" means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller or a local publicly owned electric utility is required to procure pursuant to this article.

(j) "Retail seller" means an entity engaged in the retail sale of electricity to end-use customers located within the state, including any of the following:

(1) An electrical corporation, as defined in Section 218.

(2) A community choice aggregator. A community choice aggregator shall participate in the renewables portfolio standard program subject to the same terms and conditions applicable to an electrical corporation.

(3) An electric service provider, as defined in Section 218.3. The electric service provider shall be subject to the same terms and conditions applicable to an electrical corporation pursuant to this article. This paragraph does not impair a contract entered into between an electric service provider and a retail customer prior to the suspension of direct access by the commission pursuant to Section 80110 of the Water Code.

(4) "Retail seller" does not include any of the following:

(A) A corporation or person employing cogeneration technology or producing electricity consistent with subdivision (b) of Section 218.

(B) The Department of Water Resources acting in its capacity pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(C) A local publicly owned electric utility.

(k) "WECC" means the Western Electricity Coordinating Council of the North American Electric Reliability Corporation, or a successor to the corporation.

SEC. 19. Section 399.13 of the Public Utilities Code is amended to read:

399.13. (a) (1) The commission shall direct each electrical corporation to annually prepare a renewable energy procurement plan that includes the matter in paragraph (5), to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary. The commission shall require all other retail sellers to prepare and submit renewable energy procurement plans that address the requirements identified in paragraph (5).

(2) Every electrical corporation that owns electrical transmission facilities shall annually prepare, as part of the Federal Energy Regulatory Commission Order 890 process, and submit to the commission, a report identifying any electrical transmission facility, upgrade, or enhancement that is reasonably necessary to achieve the renewables portfolio standard procurement requirements of this article. Each report shall look forward at least five years and, to ensure that adequate investments are made in a timely manner, shall include a preliminary schedule when an application for a certificate of public convenience and necessity will be made, pursuant to Chapter 5 (commencing with Section 1001), for any electrical transmission facility identified as being reasonably necessary to achieve the renewable energy resources procurement requirements of this article. Each electrical corporation that owns electrical transmission facilities shall ensure that project-specific interconnection studies are completed in a timely manner.

(3) The commission shall direct each retail seller to prepare and submit an annual compliance report that includes all of the following:

(A) The current status and progress made during the prior year toward procurement of eligible renewable energy resources as a percentage of retail sales, including, if applicable, the status of any necessary siting and permitting approvals from federal, state, and local agencies for those eligible renewable energy resources procured by the retail seller, and the current status of compliance with the portfolio content requirements of subdivision (c) of Section 399.16, including procurement of eligible renewable energy resources located outside the state and within the WECC and unbundled renewable energy credits.

(B) If the retail seller is an electrical corporation, the current status and progress made during the prior year toward construction of, and upgrades to, transmission and distribution facilities and other electrical system components it owns to interconnect eligible renewable energy resources and to supply the electricity generated by those resources to load, including

the status of planning, siting, and permitting transmission facilities by federal, state, and local agencies.

(C) Recommendations to remove impediments to making progress toward achieving the renewable energy resources procurement requirements established pursuant to this article.

(4) The commission shall adopt, by rulemaking, all of the following:

(A) A process that provides criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources to comply with the California Renewables Portfolio Standard Program obligations on a total cost and best-fit basis. This process shall take into account all of the following:

(i) Estimates of indirect costs associated with needed transmission investments.

(ii) The cost impact of procuring the eligible renewable energy resources on the electrical corporation's electricity portfolio.

(iii) The viability of the project to construct and reliably operate the eligible renewable energy resource, including the developer's experience, the feasibility of the technology used to generate electricity, and the risk that the facility will not be built, or that construction will be delayed, with the result that electricity will not be supplied as required by the contract.

(iv) Workforce recruitment, training, and retention efforts, including the employment growth associated with the construction and operation of eligible renewable energy resources and goals for recruitment and training of women, minorities, and disabled veterans.

(v) (I) Estimates of electrical corporation expenses resulting from integrating and operating eligible renewable energy resources, including, but not limited to, any additional wholesale energy and capacity costs associated with integrating each eligible renewable resource.

(II) No later than December 31, 2015, the commission shall approve a methodology for determining the integration costs described in subclause (I).

(vi) Consideration of any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code).

(vii) Consideration of capacity and system reliability of the eligible renewable energy resource to ensure grid reliability.

(B) Rules permitting retail sellers to accumulate, beginning January 1, 2011, excess procurement in one compliance period to be applied to any subsequent compliance period. The rules shall apply equally to all retail sellers. In determining the quantity of excess procurement for the applicable compliance period, the commission shall retain the rules adopted by the commission and in effect as of January 1, 2015, for the compliance period specified in subparagraphs (A) to (C), inclusive, of paragraph (1) of subdivision (b) of Section 399.15. For any subsequent compliance period, the rules shall allow the following:

(i) For electricity products meeting the portfolio content requirements of paragraph (1) of subdivision (b) of Section 399.16, contracts of any duration may count as excess procurement.

(ii) Electricity products meeting the portfolio content requirements of paragraph (2) or (3) of subdivision (b) of Section 399.16 shall not be counted as excess procurement. Contracts of any duration for electricity products meeting the portfolio content requirements of paragraph (2) or (3) of subdivision (b) of Section 399.16 that are credited towards a compliance period shall not be deducted from a retail seller's procurement for purposes of calculating excess procurement.

(iii) If a retail seller notifies the commission that it will comply with the provisions of subdivision (b) for the compliance period beginning January 1, 2017, the provisions of clauses (i) and (ii) shall take effect for that retail seller for that compliance period.

(C) Standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators. A contract for the purchase of electricity generated by an eligible renewable energy resource, at a minimum, shall include the renewable energy credits associated with all electricity generation specified under the contract. The standard terms and conditions shall include the requirement that, no later than six months after the commission's approval of an electricity purchase agreement entered into pursuant to this article, the following information about the agreement shall be disclosed by the commission: party names, resource type, project location, and project capacity.

(D) An appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to mitigate the risk that renewable projects planned or under contract are delayed or canceled. This paragraph does not preclude an electrical corporation from voluntarily proposing a margin of procurement above the appropriate minimum margin established by the commission.

(5) Consistent with the goal of increasing California's reliance on eligible renewable energy resources, the renewable energy procurement plan shall include all of the following:

(A) An assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of eligible renewable energy resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.

(B) Potential compliance delays related to the conditions described in paragraph (5) of subdivision (b) of Section 399.15.

(C) A bid solicitation setting forth the need for eligible renewable energy resources of each deliverability characteristic, required online dates, and locational preferences, if any.

(D) A status update on the development schedule of all eligible renewable energy resources currently under contract.

(E) Consideration of mechanisms for price adjustments associated with the costs of key components for eligible renewable energy resource projects with online dates more than 24 months after the date of contract execution.

(F) An assessment of the risk that an eligible renewable energy resource will not be built, or that construction will be delayed, with the result that electricity will not be delivered as required by the contract.

(6) In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years duration, unless the commission approves of a contract of shorter duration.

(7) In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.

(8) In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.

(b) A retail seller may enter into a combination of long- and short-term contracts for electricity and associated renewable energy credits. Beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the renewables portfolio standard requirement of each compliance period shall be from its contracts of 10 years or more in duration or in its ownership or ownership agreements for eligible renewable energy resources.

(c) The commission shall review and accept, modify, or reject each electrical corporation's renewable energy resource procurement plan prior to the commencement of renewable energy procurement pursuant to this article by an electrical corporation. The commission shall assess adherence to the approved renewable energy resource procurement plans in determining compliance with the obligations of this article.

(d) Unless previously preapproved by the commission, an electrical corporation shall submit a contract for the generation of an eligible renewable energy resource to the commission for review and approval consistent with an approved renewable energy resource procurement plan. If the commission determines that the bid prices are elevated due to a lack of effective competition among the bidders, the commission shall direct the electrical corporation to renegotiate the contracts or conduct a new solicitation.

(e) If an electrical corporation fails to comply with a commission order adopting a renewable energy resource procurement plan, the commission shall exercise its authority to require compliance.

(f) (1) The commission may authorize a procurement entity to enter into contracts on behalf of customers of a retail seller for electricity products from eligible renewable energy resources to satisfy the retail seller's renewables portfolio standard procurement requirements. The commission shall not require any person or corporation to act as a procurement entity or require any party to purchase eligible renewable energy resources from a procurement entity.

(2) Subject to review and approval by the commission, the procurement entity shall be permitted to recover reasonable administrative and procurement costs through the retail rates of end-use customers that are served by the procurement entity and are directly benefiting from the procurement of eligible renewable energy resources.

(g) Procurement and administrative costs associated with contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article and approved by the commission are reasonable and prudent and shall be recoverable in rates.

(h) Construction, alteration, demolition, installation, and repair work on an eligible renewable energy resource that receives production incentives pursuant to Section 25742 of the Public Resources Code, including work performed to qualify, receive, or maintain production incentives, are "public works" for the purposes of Chapter 1 (commencing with Section 1720) of Part 7 of Division 2 of the Labor Code.

SEC. 20. Section 399.15 of the Public Utilities Code is amended to read:

399.15. (a) In order to fulfill unmet long-term resource needs, the commission shall establish a renewables portfolio standard requiring all retail sellers to procure a minimum quantity of electricity products from eligible renewable energy resources as a specified percentage of total kilowatthours sold to their retail end-use customers each compliance period to achieve the targets established under this article. For any retail seller procuring at least 14 percent of retail sales from eligible renewable energy resources in 2010, the deficits associated with any previous renewables portfolio standard shall not be added to any procurement requirement pursuant to this article.

(b) The commission shall implement renewables portfolio standard procurement requirements only as follows:

(1) Each retail seller shall procure a minimum quantity of eligible renewable energy resources for each of the following compliance periods:

(A) January 1, 2011, to December 31, 2013, inclusive.

(B) January 1, 2014, to December 31, 2016, inclusive.

(C) January 1, 2017, to December 31, 2020, inclusive.

(D) January 1, 2021, to December 31, 2024, inclusive.

(E) January 1, 2025, to December 31, 2027, inclusive.

(F) January 1, 2028, to December 31, 2030, inclusive.

(2) (A) No later than January 1, 2017, the commission shall establish the quantity of electricity products from eligible renewable energy resources to be procured by the retail seller for each compliance period. These quantities shall be established in the same manner for all retail sellers and result in the same percentages used to establish compliance period quantities for all retail sellers.

(B) In establishing quantities for the compliance period from January 1, 2011, to December 31, 2013, inclusive, the commission shall require procurement for each retail seller equal to an average of 20 percent of retail sales. For the following compliance periods, the quantities shall reflect reasonable progress in each of the intervening years sufficient to ensure that

the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030. The commission shall establish appropriate three-year compliance periods for all subsequent years that require retail sellers to procure not less than 50 percent of retail sales of electricity products from eligible renewable energy resources.

(C) Retail sellers shall be obligated to procure no less than the quantities associated with all intervening years by the end of each compliance period. Retail sellers shall not be required to demonstrate a specific quantity of procurement for any individual intervening year.

(3) The commission may require the procurement of eligible renewable energy resources in excess of the quantities specified in paragraph (2).

(4) Only for purposes of establishing the renewables portfolio standard procurement requirements of paragraph (1) and determining the quantities pursuant to paragraph (2), the commission shall include all electricity sold to retail customers by the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code in the calculation of retail sales by an electrical corporation.

(5) The commission shall waive enforcement of this section if it finds that the retail seller has demonstrated any of the following conditions are beyond the control of the retail seller and will prevent compliance:

(A) There is inadequate transmission capacity to allow for sufficient electricity to be delivered from proposed eligible renewable energy resource projects using the current operational protocols of the Independent System Operator. In making its findings relative to the existence of this condition with respect to a retail seller that owns transmission lines, the commission shall consider both of the following:

(i) Whether the retail seller has undertaken, in a timely fashion, reasonable measures under its control and consistent with its obligations under local, state, and federal laws and regulations, to develop and construct new transmission lines or upgrades to existing lines intended to transmit electricity generated by eligible renewable energy resources. In determining the reasonableness of a retail seller's actions, the commission shall consider the retail seller's expectations for full-cost recovery for these transmission lines and upgrades.

(ii) Whether the retail seller has taken all reasonable operational measures to maximize cost-effective deliveries of electricity from eligible renewable energy resources in advance of transmission availability.

(B) Permitting, interconnection, or other circumstances that delay procured eligible renewable energy resource projects, or there is an insufficient supply of eligible renewable energy resources available to the retail seller. In making a finding that this condition prevents timely compliance, the commission shall consider whether the retail seller has done all of the following:

(i) Prudently managed portfolio risks, including relying on a sufficient number of viable projects.

(ii) Sought to develop one of the following: its own eligible renewable energy resources, transmission to interconnect to eligible renewable energy resources, or energy storage used to integrate eligible renewable energy resources. This clause shall not require an electrical corporation to pursue development of eligible renewable energy resources pursuant to Section 399.14.

(iii) Procured an appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to compensate for foreseeable delays or insufficient supply.

(iv) Taken reasonable measures, under the control of the retail seller, to procure cost-effective distributed generation and allowable unbundled renewable energy credits.

(C) Unanticipated curtailment of eligible renewable energy resources if the waiver would not result in an increase in greenhouse gas emissions.

(D) Unanticipated increase in retail sales due to transportation electrification. In making a finding that this condition prevents timely compliance, the commission shall consider all of the following:

(i) Whether transportation electrification significantly exceeded forecasts in that retail seller's service territory based on the best and most recently available information filed with the State Air Resources Board, the Energy Commission, or other state agency.

(ii) Whether the retail seller has taken reasonable measures to procure sufficient resources to account for unanticipated increases in retail sales due to transportation electrification.

(6) If the commission waives the compliance requirements of this section, the commission shall establish additional reporting requirements on the retail seller to demonstrate that all reasonable actions under the control of the retail seller are taken in each of the intervening years sufficient to satisfy future procurement requirements.

(7) The commission shall not waive enforcement pursuant to this section, unless the retail seller demonstrates that it has taken all reasonable actions under its control, as set forth in paragraph (5), to achieve full compliance.

(8) If a retail seller fails to procure sufficient eligible renewable energy resources to comply with a procurement requirement pursuant to paragraphs (1) and (2) and fails to obtain an order from the commission waiving enforcement pursuant to paragraph (5), the commission shall assess penalties for noncompliance. A schedule of penalties shall be adopted by the commission that shall be comparable for electrical corporations and other retail sellers. For electrical corporations, the cost of any penalties shall not be collected in rates. Any penalties collected under this article shall be deposited into the Electric Program Investment Charge Fund and used for the purposes described in Chapter 8.1 (commencing with Section 25710) of Division 15 of the Public Resources Code.

(9) Deficits associated with the compliance period shall not be added to a future compliance period.

(c) The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. This limitation shall be set at a level that prevents disproportionate rate impacts.

(d) If the cost limitation for an electrical corporation is insufficient to support the projected costs of meeting the renewables portfolio standard procurement requirements, the electrical corporation may refrain from entering into new contracts or constructing facilities beyond the quantity that can be procured within the limitation, unless eligible renewable energy resources can be procured without exceeding a de minimis increase in rates, consistent with the long-term procurement plan established for the electrical corporation pursuant to Section 454.5.

(e) (1) The commission shall monitor the status of the cost limitation for each electrical corporation in order to ensure compliance with this article.

(2) If the commission determines that an electrical corporation may exceed its cost limitation prior to achieving the renewables portfolio standard procurement requirements, the commission shall do both of the following within 60 days of making that determination:

(A) Investigate and identify the reasons why the electrical corporation may exceed its annual cost limitation.

(B) Notify the appropriate policy and fiscal committees of the Legislature that the electrical corporation may exceed its cost limitation, and include the reasons why the electrical corporation may exceed its cost limitation.

(f) The establishment of a renewables portfolio standard shall not constitute implementation by the commission of the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617).

SEC. 21. Section 399.16 of the Public Utilities Code is amended to read:

399.16. (a) Various electricity products from eligible renewable energy resources located within the WECC transmission network service area shall be eligible to comply with the renewables portfolio standard procurement requirements in Section 399.15. These electricity products may be differentiated by their impacts on the operation of the grid in supplying electricity, as well as meeting the requirements of this article.

(b) Consistent with the goals of procuring the least-cost and best-fit electricity products from eligible renewable energy resources that meet project viability principles adopted by the commission pursuant to paragraph (4) of subdivision (a) of Section 399.13 and that provide the benefits set forth in Section 399.11, a balanced portfolio of eligible renewable energy resources shall be procured consisting of the following portfolio content categories:

(1) Eligible renewable energy resource electricity products that meet either of the following criteria:

(A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities

used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or subhourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category.

(B) Have an agreement to dynamically transfer electricity to a California balancing authority.

(2) Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

(3) Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraph (1) or (2).

(c) In order to achieve a balanced portfolio, all retail sellers shall meet the following requirements for all procurement credited toward each compliance period:

(1) Not less than 50 percent for the compliance period ending December 31, 2013, 65 percent for the compliance period ending December 31, 2016, and 75 percent for each compliance period thereafter, of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (1) of subdivision (b).

(2) Not more than 25 percent for the compliance period ending December 31, 2013, 15 percent for the compliance period ending December 31, 2016, and 10 percent for each compliance period thereafter, of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (3) of subdivision (b).

(3) Any renewable energy resources contracts executed on or after June 1, 2010, not subject to the limitations of paragraph (1) or (2), shall meet the product content requirements of paragraph (2) of subdivision (b).

(4) For purposes of electric service providers only, the restrictions in this subdivision on crediting eligible renewable energy resource electricity products to each compliance period shall apply to contracts executed after January 13, 2011.

(d) Any contract or ownership agreement originally executed prior to June 1, 2010, shall count in full toward the procurement requirements established pursuant to this article, if all of the following conditions are met:

(1) The renewable energy resource was eligible under the rules in place as of the date when the contract was executed.

(2) For an electrical corporation, the contract has been approved by the commission, even if that approval occurs after June 1, 2010.

(3) Any contract amendments or modifications occurring after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual

generation, or substitute a different renewable energy resource. The duration of the contract may be extended if the original contract specified a procurement commitment of 15 or more years.

(e) A retail seller may apply to the commission for a reduction of a procurement content requirement of subdivision (c). The commission may reduce a procurement content requirement of subdivision (c) to the extent the retail seller demonstrates that it cannot comply with that subdivision because of conditions beyond the control of the retail seller as provided in paragraph (5) of subdivision (b) of Section 399.15. The commission shall not, under any circumstance, reduce the obligation specified in paragraph (1) of subdivision (c) below 65 percent for any compliance period obligation after December 31, 2016.

SEC. 22. Section 399.18 of the Public Utilities Code is amended to read:

399.18. (a) This section applies to an electrical corporation that as of January 1, 2010, met either of the following conditions:

(1) Served 30,000 or fewer customer accounts in California and had issued at least four solicitations for eligible renewable energy resources prior to June 1, 2010.

(2) Had 1,000 or fewer customer accounts in California and was not connected to any transmission system or to the Independent System Operator.

(b) For an electrical corporation or its successor, electricity products from eligible renewable energy resources may be used for compliance with this article, notwithstanding any procurement content limitation in Section 399.16, provided that all of the following conditions are met:

(1) The electrical corporation or its successor participates in, and complies with, the accounting system administered by the Energy Commission pursuant to subdivision (b) of Section 399.25.

(2) The Energy Commission verifies that the electricity generated by the facility is eligible to meet the requirements of Section 399.15.

(3) The electrical corporation continues to satisfy either of the conditions described in subdivision (a).

SEC. 23. Section 399.21 of the Public Utilities Code is amended to read:

399.21. (a) The commission, by rule, shall authorize the use of renewable energy credits to satisfy the renewables portfolio standard procurement requirements established pursuant to this article, subject to the following conditions:

(1) The commission and the Energy Commission shall ensure that the tracking system established pursuant to subdivision (c) of Section 399.25, is operational, is capable of independently verifying that electricity earning the credit is generated by an eligible renewable energy resource, and can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the WECC.

(2) Each renewable energy credit shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state.

(3) All revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers.

(4) Renewable energy credits shall not be created for electricity generated pursuant to any electricity purchase contract with a retail seller or a local publicly owned electric utility executed before January 1, 2005, unless the contract contains explicit terms and conditions specifying the ownership or disposition of those credits. Procurement under those contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.25 and included in the quantity of eligible renewable energy resources of the purchasing retail seller pursuant to Section 399.15.

(5) Renewable energy credits shall not be created for electricity generated under any electricity purchase contract executed after January 1, 2005, pursuant to the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Sec. 2601 et seq.). Procurement under the electricity purchase contracts shall be tracked through the accounting system implemented by the Energy Commission pursuant to subdivision (b) of Section 399.25 and count toward the renewables portfolio standard procurement requirements of the purchasing retail seller.

(6) Nothing in the amendments to this article made by the Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350 of the 2015–16 Regular Session) is intended to change commission Decision 11-12-052 regarding the classification of renewable energy credits from generation on the customer side of the meter.

(7) A renewable energy credit shall not be eligible for compliance with a renewables portfolio standard procurement requirement unless it is retired in the tracking system established pursuant to subdivision (c) of Section 399.25 by the retail seller or local publicly owned electric utility within 36 months from the initial date of generation of the associated electricity.

(b) The commission shall allow an electrical corporation to recover the reasonable costs of purchasing, selling, and administering renewable energy credit contracts in rates.

SEC. 24. Section 399.30 of the Public Utilities Code is amended to read:

399.30. (a) (1) To fulfill unmet long-term generation resource needs, each local publicly owned electric utility shall adopt and implement a renewable energy resources procurement plan that requires the utility to procure a minimum quantity of electricity products from eligible renewable energy resources, including renewable energy credits, as a specified percentage of total kilowatthours sold to the utility's retail end-use customers, each compliance period, to achieve the targets of subdivision (c).

(2) Beginning January 1, 2019, a local publicly owned electric utility subject to Section 9621 shall incorporate the renewable energy resources procurement plan required by this section as part of a broader integrated resource plan developed and adopted pursuant to Section 9621.

(b) The governing board shall implement procurement targets for a local publicly owned electric utility that require the utility to procure a minimum quantity of eligible renewable energy resources for each of the following compliance periods:

(1) January 1, 2011, to December 31, 2013, inclusive.

(2) January 1, 2014, to December 31, 2016, inclusive.

(3) January 1, 2017, to December 31, 2020, inclusive.
(4) January 1, 2021, to December 31, 2024, inclusive.
(5) January 1, 2025, to December 31, 2027, inclusive.
(6) January 1, 2028, to December 31, 2030, inclusive.

(c) The governing board of a local publicly owned electric utility shall ensure all of the following:

(1) The quantities of eligible renewable energy resources to be procured for the compliance period from January 1, 2011, to December 31, 2013, inclusive, are equal to an average of 20 percent of retail sales.

(2) The quantities of eligible renewable energy resources to be procured for all other compliance periods reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030. The Energy Commission shall establish appropriate multiyear compliance periods for all subsequent years that require the local publicly owned electric utility to procure not less than 50 percent of retail sales of electricity products from eligible renewable energy resources.

(3) A local publicly owned electric utility shall adopt procurement requirements consistent with Section 399.16.

(4) Beginning January 1, 2014, in calculating the procurement requirements under this article, a local publicly owned electric utility may exclude from its total retail sales the kilowatthours generated by an eligible renewable energy resource that is credited to a participating customer pursuant to a voluntary green pricing or shared renewable generation program. Any exclusion shall be limited to electricity products that do not meet the portfolio content criteria set forth in paragraph (2) or (3) of subdivision (b) of Section 399.16. Any renewable energy credits associated with electricity credited to a participating customer shall not be used for compliance with procurement requirements under this article, shall be retired on behalf of the participating customer, and shall not be further sold, transferred, or otherwise monetized for any purpose. To the extent possible for generation that is excluded from retail sales under this subdivision, a local publicly owned electric utility shall seek to procure those eligible renewable energy resources that are located in reasonable proximity to program participants.

(d) (1) The governing board of a local publicly owned electric utility shall adopt procurement requirements consistent with subparagraph (B) of paragraph (4) of subdivision (a) of, and subdivision (b) of, Section 399.13.

(2) The governing board of a local publicly owned electric utility may adopt the following measures:

(A) Conditions that allow for delaying timely compliance consistent with subdivision (b) of Section 399.15.

(B) Cost limitations for procurement expenditures consistent with subdivision (c) of Section 399.15.

(e) The governing board of the local publicly owned electric utility shall adopt a program for the enforcement of this article. The program shall be adopted at a publicly noticed meeting offering all interested parties an opportunity to comment. Not less than 30 days' notice shall be given to the public of any meeting held for purposes of adopting the program. Not less than 10 days' notice shall be given to the public before any meeting is held to make a substantive change to the program.

(f) (1) Each local publicly owned electric utility shall annually post notice, in accordance with Chapter 9 (commencing with Section 54950) of Part 1 of Division 2 of Title 5 of the Government Code, whenever its governing body will deliberate in public on its renewable energy resources procurement plan.

(2) Contemporaneous with the posting of the notice of a public meeting to consider the renewable energy resources procurement plan, the local publicly owned electric utility shall notify the Energy Commission of the date, time, and location of the meeting in order to enable the Energy Commission to post the information on its Internet Web site. This requirement is satisfied if the local publicly owned electric utility provides the uniform resource locator (URL) that links to this information.

(3) Upon distribution to its governing body of information related to its renewable energy resources procurement status and future plans, for its consideration at a noticed public meeting, the local publicly owned electric utility shall make that information available to the public and shall provide the Energy Commission with an electronic copy of the documents for posting on the Energy Commission's Internet Web site. This requirement is satisfied if the local publicly owned electric utility provides the uniform resource locator (URL) that links to the documents or information regarding other manners of access to the documents.

(g) A public utility district that receives all of its electricity pursuant to a preference right adopted and authorized by the United States Congress pursuant to Section 4 of the Trinity River Division Act of August 12, 1955 (Public Law 84-386) shall be in compliance with the renewable energy procurement requirements of this article.

(h) For a local publicly owned electric utility that was in existence on or before January 1, 2009, that provides retail electric service to 15,000 or fewer customer accounts in California, and is interconnected to a balancing authority located outside this state but within the WECC, an eligible renewable energy resource includes a facility that is located outside California that is connected to the WECC transmission system, if all of the following conditions are met:

(1) The electricity generated by the facility is procured by the local publicly owned electric utility, is delivered to the balancing authority area in which the local publicly owned electric utility is located, and is not used to fulfill renewable energy procurement requirements of other states.

(2) The local publicly owned electric utility participates in, and complies with, the accounting system administered by the Energy Commission pursuant to this article.

(3) The Energy Commission verifies that the electricity generated by the facility is eligible to meet the renewables portfolio standard procurement requirements.

(i) Notwithstanding subdivision (a), for a local publicly owned electric utility that is a joint powers authority of districts established pursuant to state law on or before January 1, 2005, that furnish electric services other than to residential customers, and is formed pursuant to the Irrigation District Law (Division 11 (commencing with Section 20500) of the Water Code), the percentage of total kilowatthours sold to the district's retail end-use customers, upon which the renewables portfolio standard procurement requirements in subdivision (b) are calculated, shall be based on the authority's average retail sales over the previous seven years. If the authority has not furnished electric service for seven years, then the calculation shall be based on average retail sales over the number of completed years during which the authority has provided electric service.

(j) A local publicly owned electric utility in a city and county that only receives greater than 67 percent of its electricity sources from hydroelectric generation located within the state that it owns and operates, and that does not meet the definition of a "renewable electrical generation facility" pursuant to Section 25741 of the Public Resources Code, shall be required to procure eligible renewable energy resources, including renewable energy credits, to meet only the electricity demands unsatisfied by its hydroelectric generation in any given year, in order to satisfy its renewable energy procurement requirements.

(k) (1) A local publicly owned electric utility that receives greater than 50 percent of its annual retail sales from its own hydroelectric generation that is not an eligible renewable energy resource shall not be required to procure additional eligible renewable energy resources in excess of either of the following:

(A) The portion of its retail sales not supplied by its own hydroelectric generation. For these purposes, retail sales supplied by an increase in hydroelectric generation resulting from an increase in the amount of water stored by a dam because the dam is enlarged or otherwise modified after December 31, 2012, shall not count as being retail sales supplied by the utility's own hydroelectric generation.

(B) The cost limitation adopted pursuant to this section.

(2) For the purposes of this subdivision, "hydroelectric generation" means electricity generated from a hydroelectric facility that satisfies all of the following:

(A) Is owned solely and operated by the local publicly owned electric utility as of 1967.

(B) Serves a local publicly owned electric utility with a distribution system demand of less than 150 megawatts.

(C) Involves a contract in which an electrical corporation receives the benefit of the electric generation through June of 2014, at which time the benefit reverts back to the ownership and control of the local publicly owned electric utility.

(D) Has a maximum penstock flow capacity of no more than 3,200 cubic feet per second and includes a regulating reservoir with a small hydroelectric generation facility producing fewer than 20 megawatts with a maximum penstock flow capacity of no more than 3,000 cubic feet per second.

(3) This subdivision does not reduce or eliminate any renewable procurement requirement for any compliance period ending prior to January 1, 2014.

(4) This subdivision does not require a local publicly owned electric utility to purchase additional eligible renewable energy resources in excess of the procurement requirements of subdivision (c).

(*l*) (1) (A) For purposes of this subdivision, "large hydroelectric generation" means electricity generated from a hydroelectric facility that is not an eligible renewable energy resource and provides electricity to a local publicly owned electric utility from facilities owned by the federal government as a part of the federal Central Valley Project or a joint powers agency formed and created pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

(B) Large hydroelectric generation does not include any resource that meets the definition of hydroelectric generation set forth in subdivision (k).

(2) If, during a year within a compliance period set forth in subdivision (b), a local publicly owned electric utility receives greater than 50 percent of its retail sales from large hydroelectric generation, it is not required to procure eligible renewable energy resources that exceed the lesser of the following for that year:

(A) The portion of the local publicly owned electric utility retail sales unsatisfied by the local publicly owned electric utility's large hydroelectric generation.

(B) The soft target adopted by the Energy Commission for the intervening year of the relevant compliance period.

(3) Except for an existing agreement effective as of January 1, 2015, or extension or renewal of that agreement, any new procurement commitment shall not be eligible to count towards the determination that the local publicly owned electric utility receives more than 50 percent of its retail sales from large hydroelectric generation in any year.

(4) The Energy Commission shall adjust the total quantities of eligible renewable energy resources to be procured by a local publicly owned electric utility for a compliance period to reflect any reductions required pursuant to paragraph (2).

(5) This subdivision does not modify the compliance obligation of a local publicly owned electric utility to satisfy the requirements of subdivision (c) of Section 399.16.

(m) (1) (A) For purposes of this subdivision, "unavoidable long-term contracts and ownership agreements" means commitments for electricity from a coal-fired powerplant, located outside the state, originally entered into by a local publicly owned electric utility before June 1, 2010, that is not subsequently modified to result in an extension of the duration of the

agreement or result in an increase in total quantities of energy delivered during any compliance period set forth in subdivision (b).

(B) The governing board of a local publicly owned electric utility shall demonstrate in its renewable energy resources procurement plan required pursuant to subdivision (f) that any cancellation or divestment of the commitment would result in significant economic harm to its retail customers that cannot be substantially mitigated through resale, transfer to another entity, early closure of the facility, or other feasible measures.

(2) For the compliance period set forth in paragraph (4) of subdivision (b), a local publicly owned electric utility meeting the requirement of subparagraph (B) of paragraph (1) may adjust its renewable energy procurement targets to ensure that the procurement of additional electricity from eligible renewable energy resources, in combination with the procurement of electricity from unavoidable long-term contracts and ownership agreements, does not exceed the total retail sales of the local publicly owned electric utility during that compliance period. The local publicly owned electric utility may limit its procurement of eligible renewable energy resources for that compliance period to no less than an average of 33 percent of its retail sales.

(3) The Energy Commission shall approve any reductions in procurement targets proposed by a local publicly owned electric utility if it determines that the requirements of this subdivision are satisfied.

(n) A local publicly owned electric utility shall retain discretion over both of the following:

(1) The mix of eligible renewable energy resources procured by the utility and those additional generation resources procured by the utility for purposes of ensuring resource adequacy and reliability.

(2) The reasonable costs incurred by the utility for eligible renewable energy resources owned by the utility.

(o) The Energy Commission shall adopt regulations specifying procedures for enforcement of this article. The regulations shall include a public process under which the Energy Commission may issue a notice of violation and correction against a local publicly owned electric utility for failure to comply with this article, and for referral of violations to the State Air Resources Board for penalties pursuant to subdivision (n).

(p) (1) Upon a determination by the Energy Commission that a local publicly owned electric utility has failed to comply with this article, the Energy Commission shall refer the failure to comply with this article to the State Air Resources Board, which may impose penalties to enforce this article consistent with Part 6 (commencing with Section 38580) of Division 25.5 of the Health and Safety Code. Any penalties imposed shall be comparable to those adopted by the commission for noncompliance by retail sellers.

(2) Any penalties collected by the State Air Resources Board pursuant to this article shall be deposited in the Air Pollution Control Fund and, upon appropriation by the Legislature, shall be expended for reducing emissions

of air pollution or greenhouse gases within the same geographic area as the local publicly owned electric utility.

SEC. 25. Article 17 (commencing with Section 400) is added to Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, to read:

Article 17. Clean Energy and Pollution Reduction

400. The commission and the Energy Commission shall do all of the following in furtherance of meeting the state's clean energy and pollution reduction objectives:

(a) Take into account the use of distributed generation to the extent that it provides economic and environmental benefits in disadvantaged communities as identified pursuant to Section 39711 of the Health and Safety Code.

(b) Take into account the opportunities to decrease costs and increase benefits, including pollution reduction and grid integration, using renewable and nonrenewable technologies with zero or lowest feasible emissions of greenhouse gases, criteria pollutants, and toxic air contaminants onsite in proceedings associated with meeting the objectives.

(c) Where feasible, authorize procurement of resources to provide grid reliability services that minimize reliance on system power and fossil fuel resources and, where feasible, cost effective, and consistent with other state policy objectives, increase the use of large- and small-scale energy storage with a variety of technologies, targeted energy efficiency, demand response, including, but not limited to, automated demand response, eligible renewable energy resources, or other renewable and nonrenewable technologies with zero or lowest feasible emissions of greenhouse gases, criteria pollutants, and toxic air contaminants onsite to protect system reliability.

(d) Review technology incentive, research, development, deployment, and market facilitation programs overseen by the commission and the Energy Commission and make recommendations to advance state clean energy and pollution reduction objectives and provide benefits to disadvantaged communities as identified pursuant to Section 39711 of the Health and Safety Code.

(e) To the extent feasible, give first priority to the manufacture and deployment of clean energy and pollution reduction technologies that create employment opportunities, including high wage, highly skilled employment opportunities, and increased investment in the state.

(f) Establish a publicly available tracking system to provide up-to-date information on progress toward meeting the clean energy and pollution reduction goals of the Clean Energy and Pollution Reduction Act of 2015.

(g) Establish an advisory group consisting of representatives from disadvantaged communities identified in Section 39711 of the Health and Safety Code. The advisory group shall review and provide advice on programs proposed to achieve clean energy and pollution reduction and

determine whether those proposed programs will be effective and useful in disadvantaged communities.

SEC. 26. Section 454.51 is added to the Public Utilities Code, to read:

454.51. The commission shall do all of the following:

(a) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio shall rely upon zero carbon-emitting resources to the maximum extent reasonable and be designed to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation.

(b) Direct each electrical corporation to include, as part of its proposed procurement plan, a strategy for procuring best-fit and least-cost resources to satisfy the portfolio needs identified by the commission pursuant to subdivision (a).

(c) Ensure that the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a) are allocated on a fully nonbypassable basis consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1.

(d) Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration need identified in subdivision (a). If the commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:

(1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.

(2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.

(3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.

(4) All costs resulting from nonperformance will be borne by the electrical corporation or community choice aggregator responsible for them.

SEC. 27. Section 454.52 is added to the Public Utilities Code, to read:

454.52. (a) (1) Commencing in 2017, and to be updated regularly thereafter, the commission shall adopt a process for each load-serving entity, as defined in Section 380, to file an integrated resource plan, and a schedule for periodic updates to the plan, to ensure that load-serving entities do the following:

(A) Meet the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in achieving the

economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

(B) Procure at least 50 percent eligible renewable energy resources by December 31, 2030, consistent with Article 16 (commencing with Section 399.11) of Chapter 2.3.

(C) Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.

(D) Minimize impacts on ratepayers' bills.

(E) Ensure system and local reliability.

(F) Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.

(G) Enhance distribution systems and demand-side energy management.

(H) Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

(2) (A) The commission may authorize all source procurement for electrical corporations that includes various resource types including demand-side resources, supply side resources, and resources that may be either demand-side resources or supply side resources, taking into account the differing electrical corporations' geographic service areas, to ensure that each load-serving entity meets the goals set forth in paragraph (1).

(B) The commission may approve procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in paragraph (1), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan.

(b) (1) Each load-serving entity shall prepare and file an integrated resource plan consistent with paragraph (2) of subdivision (a) on a time schedule directed by the commission and subject to commission review.

(2) Each electrical corporation's plan shall follow the provisions of Section 454.5.

(3) The plan of a community choice aggregator shall be submitted to its governing board for approval and provided to the commission for certification, consistent with paragraph (5) of subdivision (a) of Section 366.2, and shall achieve the following:

(A) Economic, reliability, environmental, security, and other benefits and performance characteristics that are consistent with the goals set forth in paragraph (1) of subdivision (a).

(B) A diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.

(C) The resource adequacy requirements established pursuant to Section 380.

(4) The plan of an electric service provider shall achieve the goals set forth in paragraph (1) of subdivision (a) through a diversified portfolio consisting of both short-term and long-term electricity, electricity-related, and demand reduction products.

(c) To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.

(d) In order to eliminate redundancy and increase efficiency, the process adopted pursuant to subdivision (a) shall incorporate, and not duplicate, any other planning processes of the commission.

SEC. 28. Section 454.55 of the Public Utilities Code is amended to read:

454.55. (a) The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective electricity efficiency savings and establish efficiency targets for an electrical corporation to achieve, pursuant to Section 454.5, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(1) By July 1, 2018, and every four years thereafter, each electrical corporation shall report on its progress toward achieving the targets established pursuant to subdivision (a).

(2) By July 1, 2019, and every four years thereafter, the commission shall, pursuant to Section 9795 of the Government Code, report to the Legislature on the progress toward achieving the targets established pursuant to subdivision (a). The commission shall include specific strategies for, and an update on, progress toward maximizing the contribution of electricity efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

(b) (1) By December 31, 2023, the commission shall, in a new or existing proceeding, undertake a comprehensive review of the feasibility, costs, barriers, and benefits of achieving a cumulative doubling of energy efficiency savings and demand reduction by 2030 pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(2) Notwithstanding subdivision (c) of Section 25310 of the Public Resources Code, if the commission concludes the targets established for electrical corporations to achieve pursuant to subdivision (a) are not cost effective, feasible, or pose potential adverse impacts to public health and safety, the commission shall revise the targets to the level that optimizes the amount of energy efficiency savings and demand reduction and shall modify, revise, or update its policies as needed to address barriers preventing achievement of those targets.

SEC. 29. Section 454.56 of the Public Utilities Code is amended to read:

454.56. (a) The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective natural gas efficiency savings and establish efficiency targets for the gas corporation to achieve, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(b) A gas corporation shall first meet its unmet resource needs through all available natural gas efficiency and demand reduction resources that are cost effective, reliable, and feasible.

(c) By July 1, 2018, and every four years thereafter, each gas corporation shall report on its progress toward achieving the targets established pursuant to subdivision (a).

(d) By July 1, 2019, and every four years thereafter, the commission shall, pursuant to Section 9795 of the Government Code, report to the Legislature on the progress toward achieving the targets establish pursuant to subdivision (a). The commission shall include specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

(e) Notwithstanding subdivision (c) of Section 25310 of the Public Resources Code, if the commission concludes in its review pursuant to paragraph (1) of subdivision (b) of Section 454.55 that the targets established for gas corporations to achieve pursuant to subdivision (a) are not cost effective, feasible, or pose potential adverse impacts to public health and safety, the commission shall revise the targets to the level that maximizes the amount of energy efficiency savings and demand reduction and shall modify, revise, or update its policies as needed to address barriers preventing achievement of those targets.

SEC. 30. Section 701.1 of the Public Utilities Code is amended to read:

701.1. (a) (1) The Legislature finds and declares that, in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency, development of renewable energy resources, such as wind, solar, biomass, and geothermal energy, and widespread transportation electrification.

(2) The amendment made to this subdivision by the Clean Energy and Pollution Reduction Act of 2015 does not expand the authority of the commission beyond that provided by other law.

(b) The Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and which are not being exploited by any other entity.

(c) In calculating the cost-effectiveness of energy resources, including conservation and load management options, the commission shall include, in addition to other ratepayer protection objectives, a value for any costs and benefits to the environment, including air quality. The commission shall ensure that any values it develops pursuant to this section are consistent with values developed by the State Energy Resources Conservation and Development Commission pursuant to Section 25000.1 of the Public

Resources Code. However, if the commission determines that a value developed pursuant to this subdivision is not consistent with a value developed by the State Energy Resources Conservation and Development Commission pursuant to subdivision (c) of Section 25000.1 of the Public Resources Code, the commission may nonetheless use this value if, in the appropriate record of its proceedings, it states its reasons for using the value it has selected.

(d) In determining the emission values associated with the current operating capacity of existing electric powerplants pursuant to subdivision (c), the commission shall adhere to the following protocol in determining values for air quality costs and benefits to the environment. If the commission finds that an air pollutant that is subject to regulation is a component of residual emissions from an electric powerplant and that the owner of that powerplant is either of the following:

(1) Using a tradable emission allowance, right, or offset for that pollutant, which (A) has been approved by the air quality district regulating the powerplant, (B) is consistent with federal and state law, and (C) has been obtained, authorized, or acquired in a market-based system.

(2) Paying a tax per measured unit of that pollutant.

The commission shall not assign a value or cost to that residual pollutant for the current operating capacity of that powerplant because the alternative protocol for dealing with the pollutant operates to internalize its cost for the purpose of planning for and acquiring new generating resources.

(e) (1) The values determined pursuant to subdivision (c) to represent costs and benefits to the environment shall not be used by the commission, in and of themselves, to require early decommissioning or retirement of an electric utility powerplant that complies with applicable prevailing environmental regulations.

(2) Further, the environmental values determined pursuant to subdivision (c) shall not be used by the commission in a manner which, when those values are aggregated, will result in advancing an electric utility's need for new powerplant capacity by more than 15 months.

(f) This subdivision shall apply whenever a powerplant bid solicitation is required by the commission for an electric utility and a portion of the amount of new powerplant capacity, which is the subject of the bid solicitation, is the result of the commission's use of environmental values to advance that electric utility's need for new powerplant capacity in the manner authorized by paragraph (2) of subdivision (e). The affected electric utility may propose to the commission any combination of alternatives to that portion of the new powerplant capacity that is the result of the commission's use of environmental values as authorized by paragraph (2) of subdivision (c). The commission shall approve an alternative in place of the new powerplant capacity if it finds all of the following:

(1) The alternative has been approved by the relevant air quality district.

(2) The alternative is consistent with federal and state law.

(3) The alternative will result in needed system reliability for the electric utility at least equivalent to that which would result from bidding for new powerplant capacity.

(4) The alternative will result in reducing system operating costs for the electric utility over those which would result from the process of bidding for new powerplant capacity.

(5) The alternative will result in equivalent or better environmental improvements at a lower cost than would result from bidding for new powerplant capacity.

(g) This section does not require an electric utility to alter the dispatch of its powerplants for environmental purposes.

(h) This section does not preclude an electric utility from submitting to the commission any combination of alternatives to meet a commission-identified need for new capacity, if the submission is otherwise authorized by the commission.

(i) This section does not change or alter any provision of commission decision 92-04-045, dated April 22, 1992.

SEC. 31. Section 740.8 of the Public Utilities Code is amended to read:

740.8. As used in Section 740.3 or 740.12, "interests" of ratepayers, short- or long-term, mean direct benefits that are specific to ratepayers, consistent with both of the following:

(a) Safer, more reliable, or less costly gas or electrical service, consistent with Section 451, including electrical service that is safer, more reliable, or less costly due to either improved use of the electric system or improved integration of renewable energy generation.

(b) Any one of the following:

(1) Improvement in energy efficiency of travel.

(2) Reduction of health and environmental impacts from air pollution.

(3) Reduction of greenhouse gas emissions related to electricity and natural gas production and use.

(4) Increased use of alternative fuels.

(5) Creating high-quality jobs or other economic benefits, including in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

SEC. 32. Section 740.12 is added to the Public Utilities Code, to read:

740.12. (a) (1) The Legislature finds and declares all of the following:

(A) Advanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals.

(B) Widespread transportation electrification is needed to achieve the goals of the Charge Ahead California Initiative (Chapter 8.5 (commencing with Section 44258) of Part 5 of Division 26 of the Health and Safety Code).

(C) Widespread transportation electrification requires increased access for disadvantaged communities, low- and moderate-income communities, and other consumers of zero-emission and near-zero-emission vehicles, and increased use of those vehicles in those communities and by other consumers

to enhance air quality, lower greenhouse gases emissions, and promote overall benefits to those communities and other consumers.

(D) Reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification.

(E) Widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a transportation fuel.

(F) Widespread transportation electrification should stimulate innovation and competition, enable consumer options in charging equipment and services, attract private capital investments, and create high-quality jobs for Californians, where technologically feasible.

(G) Deploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.

(H) Deploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations.

(I) According to the State Alternative Fuels Plan analysis by the Energy Commission and the State Air Resources Board, light-, medium-, and heavy-duty vehicle electrification results in approximately 70 percent fewer greenhouse gases emitted, over 85 percent fewer ozone-forming air pollutants emitted, and 100 percent fewer petroleum used. These reductions will become larger as renewable generation increases.

(2) It is the policy of the state and the intent of the Legislature to encourage transportation electrification as a means to achieve ambient air quality standards and the state's climate goals. Agencies designing and implementing regulations, guidelines, plans, and funding programs to reduce greenhouse gas emissions shall take the findings described in paragraph (1) into account.

(b) The commission, in consultation with the State Air Resources Board and the Energy Commission, shall direct electrical corporations to file applications for programs and investments to accelerate widespread transportation electrification to reduce dependence on petroleum, meet air quality standards, achieve the goals set forth in the Charge Ahead California Initiative (Chapter 8.5 (commencing with Section 44258) of Part 5 of Division 26 of the Health and Safety Code), and reduce emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. Programs proposed by electrical corporations shall seek to minimize overall costs and maximize overall benefits. The commission shall approve, or modify and approve, programs and investments in transportation electrification, including those that deploy charging infrastructure, via a reasonable cost recovery mechanism, if they are consistent with this section, do not unfairly compete with nonutility

enterprises as required under Section 740.3, include performance accountability measures, and are in the interests of ratepayers as defined in Section 740.8.

(c) The commission shall review data concerning current and future electric transportation adoption and charging infrastructure utilization prior to authorizing an electrical corporation to collect new program costs related to transportation electrification in customer rates. If market barriers unrelated to the investment made by an electric corporation prevent electric transportation from adequately utilizing available charging infrastructure, the commission shall not permit additional investments in transportation electrification without a reasonable showing that the investments would not result in long-term stranded costs recoverable from ratepayers.

(d) This section applies to an application to the commission for transportation electrification programs and investments if one of the following conditions is met:

(1) The application is filed on or after January 1, 2016.

(2) The application is filed before January 1, 2016, but has an evidentiary hearing scheduled on or after July 1, 2016.

SEC. 33. Section 9505 of the Public Utilities Code is amended to read:

9505. (a) By March 15, 2013, and by March 15 of each year thereafter, each local publicly owned electric utility shall report to the Energy Commission and to its customers all of the following:

(1) Its investments in energy efficiency and demand reduction programs.

(2) A description of each energy efficiency and demand reduction program, program expenditures, the cost-effectiveness of each program, and expected and actual energy efficiency savings and demand reduction results that reflect the intent of the Legislature to encourage energy savings and reductions in emissions of greenhouse gases resulting from providing service to existing residential and nonresidential buildings, while taking into consideration the effect of the program on rates, reliability, and financial resources.

(3) The sources for funding of its energy efficiency and demand reduction programs.

(4) The methodologies and input assumptions used to determine the cost-effectiveness of its energy efficiency and demand reduction programs.

(5) A comparison of the local publicly owned electric utility's annual targets established pursuant to subdivision (b) and the local publicly owned electric utility's reported electricity efficiency savings and demand reductions.

(b) By March 15, 2013, and by March 15 of every fourth year thereafter, each local publicly owned electric utility shall identify all potentially achievable cost-effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period, consistent with the annual targets established by the Energy Commission pursuant to subdivision (c) of Section 25310 of the Public Resources Code. A local publicly owned electric utility's determination of potentially achievable cost-effective electricity efficiency

savings shall be made without regard to previous minimum investments undertaken pursuant to Section 385. A local publicly owned electric utility shall treat investments made to achieve energy efficiency savings and demand reduction targets as procurement investments.

(c) Within 60 days of establishing annual targets pursuant to subdivision (b), each local publicly owned electric utility shall report those targets to the Energy Commission, and the basis for establishing those targets.

(d) Each local publicly owned electric utility shall make available to its customers and to the Energy Commission the results of any independent evaluation that measures and verifies the energy efficiency savings and the reduction in energy demand achieved by its energy efficiency and demand reduction programs.

SEC. 34. Section 9620 of the Public Utilities Code is amended to read:

9620. (a) Each local publicly owned electric utility serving end-use customers, shall prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers. Customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218, shall not be subject to these requirements if the customer generation, or the load it serves, meets one of the following criteria:

(1) It takes standby service from the local publicly owned electric utility on a rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(2) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup power is not supplied from the electricity grid.

(3) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

(b) Each local publicly owned electric utility serving end-use customers shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(c) Each local publicly owned electric utility shall prudently plan for and procure energy storage systems that are adequate to meet the requirements of Section 2836.

(d) A local publicly owned electric utility serving end-use customers shall, upon request, provide the Energy Commission with any information the Energy Commission determines is necessary to evaluate the progress made by the local publicly owned electric utility in meeting the requirements of this section, consistent with the annual targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(e) The Energy Commission shall report to the Legislature, to be included in each integrated energy policy report prepared pursuant to Section 25302 of the Public Resources Code, regarding the progress made by each local

publicly owned electric utility serving end-use customers in meeting the requirements of this section.

SEC. 35. Section 9621 is added to the Public Utilities Code, to read:

9621. (a) This section shall apply to a local publicly owned electric utility with an annual electrical demand exceeding 700 gigawatthours, as determined on a three-year average commencing January 1, 2013.

(b) On or before January 1, 2019, the governing board of a local publicly owned electric utility shall adopt an integrated resource plan and a process for updating the plan at least once every five years to ensure the utility achieves all of the following:

(1) Meets the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each local publicly-owned electric utility that reflect the electricity sector's percentage in achieving the economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

(2) Ensures procurement of at least 50 percent eligible renewable energy resources by 2030 consistent with Article 16 (commencing with Section 399.11) of Chapter 2.3.

(3) Meets the goals specified in subparagraphs (C) to (H), inclusive, of paragraph (1) of subdivision (a) of Section 454.52.

(c) (1) The integrated resource plan shall address procurement for the following:

(A) Energy efficiency and demand response resources pursuant to Section 9615.

(B) Energy storage requirements pursuant to Chapter 7.7 (commencing with Section 2835) of Part 2 of Division 1.

(C) Transportation electrification.

(D) A diversified procurement portfolio consisting of both short-term and long-term electricity, electricity-related, and demand response products.

(E) The resource adequacy requirements established pursuant to Section 9620.

(2) (A) The governing board of the local publicly owned electric utility may authorize all source procurement that includes various resource types, including demand-side resources, supply side resources, and resources that may be either demand-side resources or supply side resources, to ensure that the local publicly owned electric utility procures the optimum resource mix that meets the objectives of subdivision (b).

(B) The governing board may authorize procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in subdivision (b), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan.

(d) A local publicly owned electric utility shall satisfy the notice and public disclosure requirements of subdivision (f) of Section 399.30 with respect to any integrated resource plan or plan update it considers.

SEC. 36. Section 9622 is added to the Public Utilities Code, to read:

9622. (a) Integrated resource plans and plan updates adopted pursuant to Section 9621 shall be submitted to the Energy Commission.

(b) The Energy Commission shall review the integrated resource plans and plan updates. If the Energy Commission determines an integrated resource plan or plan update is inconsistent with the requirements of Section 9621, the Energy Commission shall provide recommendations to correct the deficiencies.

(c) The Energy Commission may adopt guidelines to govern the submission of information and data and reports needed to support the Energy Commission's review of the utility's integrated resource plan pursuant to this section at a publicly noticed meeting offering all interested parties an opportunity to comment. The Energy Commission shall provide written public notice of not less than 30 days for the initial adoption of guidelines and not less than 10 days for the subsequent adoption of substantive changes. Notwithstanding any other law, any guidelines adopted pursuant to this section shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.

SEC. 37. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

SEC. 38. The provisions of this act are severable. If any provision of this act or its application is held invalid, that invalidity shall not affect other provisions or applications that can be given effect without the invalid provision or application.

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Clean Energy and Pollution Reduction Act of 2015 (SB 350)

Senate Bill (SB) 350 (de León, Chapter 547, 2015) requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030, including efforts to achieve at least 50 percent renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification.

CPUC Implementation Framework

Broad directives provided by SB 350 to the CPUC can be broken down into five major policy areas:

1. Integrated resource planning
2. Energy Efficiency
3. Renewable Energy
4. Transportation Electrification
5. Disadvantaged Communities

Please view our SB 350 Work Area Infographic

Each area requires collaboration with sister state agencies including the California Energy Commission and Air Resources Board. Disadvantaged community goals in SB 350 are cross-cutting and integrated into all policy areas.

The implementation of SB 350 at the CPUC will require multiple and concurrent regulatory proceedings. Please refer to the policy area pages linked above for up-to-date information on SB 350 implementation.

Past Workshops

Contact Melicia Charles at Melicia.Charles@cpuc.ca.gov if you have any questions on implementation status.

FOOTNOTE 29

Before the Energy Resources Conservation and Development Commission of the State of California
1516 Ninth Street, Sacramento, CA 95814
1-800-822-6228 – www.energy.ca.gov

APPLICATION FOR CERTIFICATION FOR THE:

PUENTE POWER PROJECT

Docket No. 15-AFC-01

COMMITTEE STATEMENT REGARDING THE STATE OF THE PRESIDING MEMBER'S PROPOSED DECISION

The Energy Commission Committee[1] (Committee) assigned to the Puente Power Project (Project) proceeding continues to work diligently in preparing a Presiding Member's Proposed Decision (PMPD) for the Project. As we do so, we find it appropriate to provide notice to the parties and interested members of the public of the current status of our deliberations.

Although the PMPD is not yet in final form, it is clear to us that the Project will be inconsistent with several Laws, Ordinances, Regulations or Standards (LORS) and will create significant unmitigable environmental effects. This, in turn, requires us to consider feasible alternatives that avoid or reduce those impacts and inconsistencies. The September 29, 2017 letter from the California Independent System Operator[2] (California ISO) addresses feasibility and informs us that preferred resource alternatives to the Project are technologically feasible. The California ISO also states that economic feasibility can only be ascertained through a new Request for Offer (RFO) process, and stresses that any such RFO would need to be expedited in order to ensure that the Mandalay facilities retire in accord with the State Water Resources Control Board's Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.

While we have no current information about whether an expedited RFO is forthcoming, the timing constraints identified by the California ISO lead us to conclude that it is prudent to communicate the Committee's position before we complete the PMPD. We cannot recommend approval of a project that creates significant unmitigable impacts or is inconsistent with LORS unless we make the override findings required by law. That decision is entirely discretionary and allows the Energy Commission to consider the

[1] The Committee consists of Commissioner Janea A. Scott, Presiding Member, and Commissioner Karen Douglas, Associate Member.
[2] TN 221345.

balance of any project benefits against the impacts the project will cause. On the record currently before us, we are unwilling to override the significant impacts or LORS inconsistencies.

For this reason, we hereby notify the parties and interested members of the public that we intend to issue a PMPD that recommends denial of the Project on the grounds that it creates inconsistencies with LORS and significant environmental impacts that cannot be mitigated. The PMPD will contain a full discussion of all issues required by applicable statutes and regulations and will identify the facts and the analytical process underlying the conclusions reached therein.

We acknowledge that this statement is unusual, but observe that it in no way impairs the rights of the applicant or any other party. All procedural requirements will continue to be honored. After the PMPD is issued, the Committee will hold a PMPD conference to receive comments and determine whether any revisions are required. The Committee will then forward the PMPD (or a revised PMPD if one is issued) to the full Commission for consideration at a public hearing. The full Commission will have the opportunity to accept, reject, or modify the PMPD's conclusions. Indeed, the decision to issue this statement underscores our commitment to producing thorough and thoughtful decisions in a transparent public process that entails rigorous adherence to applicable legal requirements.

Una traducción al español de esta declaración será fichada a principios de la próxima semana. (A Spanish translation of this statement will be filed by early next week.)

Dated: October 5, 2017, at Sacramento, California

Original signed by

JANEA A. SCOTT
Commissioner and Presiding Member
Puente Power Project AFC Committee

Original signed by

KAREN DOUGLAS
Commissioner and Associate Member
Puente Power Project AFC Committee

FOOTNOTE 30

California ISO

Moorpark Sub-Area Local Capacity Alternative Study

August 16, 2017

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1. Executive Summary

Pursuant to the California Energy Commission's (CEC) request in the June 9, 2017[1] and June 20, 2017[2] Committee orders, the California Independent System Operator Corporation (ISO) has prepared a study regarding local capacity alternatives to the Puente Power Project (Puente). In the study, the ISO analyzed three portfolios of capacity alternatives that were designed to meet the local capacity requirements (LCR) in the absence of Puente. The study does not, however, address the timing or feasibility for procurement of the alternative resources portfolios, but instead quantifies the amount of preferred resources, energy storage, and/or reactive power devices that would be necessary to meet LCR in the Moorpark sub-area.

The ISO, in consultation with Southern California Edison (SCE), developed three alternative resource scenarios to meet the Moorpark LCR in the absence of Puente. Each of these scenarios begins with a common set of incremental distributed resources that consists of an incremental 80 MW of energy storage enabled demand response resources, 25 MW of incremental photovoltaic (PV) solar/energy storage hybrid resources, and approximately 30 MW of existing slow responding demand response resources coupled with incremental energy storage to enable these resources to meet local area contingencies. This represents an incremental 135 MW of distributed resources that are assumed to be procured or properly enabled in the Moorpark sub-area under all three scenarios.

This 135 MW of incremental distributed resources is not sufficient to meet the local capacity requirements for the Moorpark sub-area. As a result, the ISO studied three scenarios to quantify the amount of additional "grid-connected" resources necessary to meet the applicable reliability criteria.[3] The ISO conducts its planning studies to adhere to NERC, WECC, and ISO transmission planning standards as well as the local capacity technical study criteria set out in the ISO tariff[4] to ensure adequate local area

[1] Committee Order Granting Applicant's Motion to Exclude the Supplemental Testimony of James H. Caldwell and Accepting the California Independent System Operator's Offer to Conduct a Special Study (TN#218016) (June 9 Order).

[2] Committee Orders Extending the Time for the California ISO Special Study, Denying the City of Oxnard's Request for Additional Time, Revising the Committee Schedule, and Cancelling the June 28, 2017 Committee Conference (TN#219815) (June 20 Order).

[3] The ISO uses North American Electric Reliability Corporation (NERC) reliability standards, Western Electricity Coordinating Council (WECC) regional criteria, ISO planning standards and local capacity technical study criteria set out in the ISO's tariff (Section 40.3.1.1, Local Capacity Technical Study Criteria). The latter was most relevant in this study.

[4] ISO Tariff Section 40.3.1.1 provides that "[t]he Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2."

reliability. In this case, the local capacity technical study criteria set out in the ISO tariff to avoid voltage collapse for the contingency events set out in the requirements are the most limiting and are the basis for establishing the volume of required local capacity.

In the Scenarios 1 and 2, the ISO determined the amount of (1) in-front-of-meter (IFOM) battery storage; or (2) dynamic reactive power, respectively, necessary to meet local capacity requirements described above. For Scenario 3, the ISO assumed the Ellwood Generating Facility, a 54 MW gas-fired plant located in the Moorpark sub-area, will retire instead of being refurbished. The ISO then determined the amount of IFOM battery storage that would be necessary under this scenario. The additional "grid-connected" resources needed to meet the local capacity technical study criteria for each of the three scenarios are detailed below:

- **Scenario 1 –** 125 MW of energy storage resources with a nine hour continuous discharge duration would be necessary to satisfy local capacity requirements consistent with the local capacity technical study criteria.
- **Scenario 2 –** A 240 Mvar reactive power device would be necessary to satisfy local capacity requirements consistent with local capacity technical study criteria. Unlike Scenario 1 and 2, however, the reactive support does not also provide protection from loss of load through load shedding to avoid thermal overloads; load shedding is not desirable but is permitted under the local capacity technical study criteria in the circumstances being studied.
- **Scenario 3 –** If the 54 MW Ellwood Generating Facility is retired rather than refurbished, 240 MW of energy storage resources would be necessary to satisfy local capacity requirements consistent with the local capacity technical study criteria. 115 MW of this energy storage capacity would need a five hour continuous discharge duration, 65 MW would need a nine hour continuous discharge duration, and 60 MW would need a ten hour continuous discharge duration.

The ISO also conducted a summary cost comparison of the alternative scenarios based on publicly available information. The ISO's cost comparison indicates that the estimated capital costs for scenarios 1 and 3 are significantly higher than the estimated capital costs for the Puente project, as shown in Table 1-1 below. The estimated capital costs for scenario 2 is only slightly higher than the Puente project but this scenario does not provide the same level of protection against post-contingency load shedding to mitigate thermal overloads. These costs represent initial installation costs and do not include ongoing operating or maintenance costs, or replacement costs to adjust for shorter expected lifespans of some equipment versus others.

Table 1-1

Capital Cost Estimates of Resource Portfolios

Resource	Description	Estimated cost (millions)
Scenario 1	Incremental distributed resources plus grid connected battery storage	$805
Scenario 2	Incremental distributed resources plus reactive device	$309-$359
Scenario 3	Incremental distributed resources plus grid connected battery storage (if the Ellwood Generating Station is retired)	$1,116
Puente Power Project	262 MW combustion turbine generator	$299

2. Introduction

2.1. Background

The California Public Utilities Commission (CPUC) authorized SCE to enter into a long term resource adequacy power purchase agreement with NRG Oxnard Energy Center, LLC (NRG) for the 262 MW gas-fired Puente facility.[5] The project was approved to offset the local capacity requirements in the Moorpark Sub-Area that result from the expected retirement of close to 2000 MW of once-through-cooled (OTC) generation at the end of 2020 due to state policy limiting the use of coastal and estuarine water. NRG subsequently applied to the CEC for certification to construct and operate the Puente facility.

In connection with its consideration of NRG's application, the CEC accepted the ISO's offer to study various portfolios of preferred resources[6] that could meet the identified need, and indicated that an ISO special study of one or more alternative resource portfolios that considers the parameters and assumptions below would be most useful.

- The necessary resources are in place to meet the reliability need in the Moorpark Sub-Area in 2021 with timely Once-Through Cooling (OTC) compliance;

[5] CPUC Decision 16-05-050.

[6] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

- The current OTC compliance deadline(s) for Ormond Beach Units 1 & 2 and Mandalay Units 1 & 2 of December 31, 2020 are not extended and the facilities retire;
- Include presently existing generation, contracted generation, and preferred resources and storage the ISO expects to be on line to meet reliability needs in the Moorpark Sub-Area by 2021; and
- To the extent that it may be helpful in identifying the type and quantity of new preferred resources and storage that could be available by 2021, the ISO may choose to review and consider SCE's 2015 Preferred Resources Pilot RFO, 2016 Aliso Canyon Energy Storage RFO, and the 2016 Aliso Canyon Design, Build, and Transfer RFP.[7]

Accordingly, the ISO developed a conceptual study scope based on the parameters and assumptions stipulated in the CEC's June 9 Order. The study was not initially intended to assess the cost, timing or feasibility of procurement of the alternative resources. The study scope was amended to include a discussion of capital costs based on publicly available information.

Starting with a common base set of assumed incremental distributed resources, the ISO's fundamental objectives for each preferred resource scenario was to determine the additional amount of grid connected battery storage or dynamic reactive power needed to meet local capacity requirements consistent with the applicable reliability criteria for the Moorpark sub-area. With respect to battery storage, the ISO examined various blocks of battery storage defined by capacity (in MW) amount and discharge duration (in hours). The ISO assessed the minimum additional energy storage discharge capacity required for each block and derived the minimum discharge duration (hours) capability of each block while operating each block at its maximum discharge capacity. In addition, the ISO verified that each energy storage block can be charged during off-peak hours given each block's charging capacity and minimum charging duration.

The studies performed to reach the objectives for each scenario included: (1) determining the minimum additional energy storage capacity requirement; (2) determining the area voltage stability load limit; (3) performing an hourly load-resource assessment; and (4) validating the resource dispatch determined in the hourly load-resource assessment.

A common base set of incremental distributed preferred resources were assumed in all scenarios and were developed through discussion with SCE staff, relying on their experience with past procurement and knowledge of electricity customer data in the Moorpark sub-area.

[7] June 9 Order, p. 4.

The ISO conducted a stakeholder call on June 30, 2017 to present and discuss the Moorpark need, the scope of the ISO study, and the draft base incremental distributed resource assumptions. Stakeholders were provided the opportunity to ask questions during the call and provide written feedback. Written comments were received from a number of parties and have been posted on the ISO's website.[8] The comments and the ISO's consideration of the feedback are summarized in Section 5 of this report.

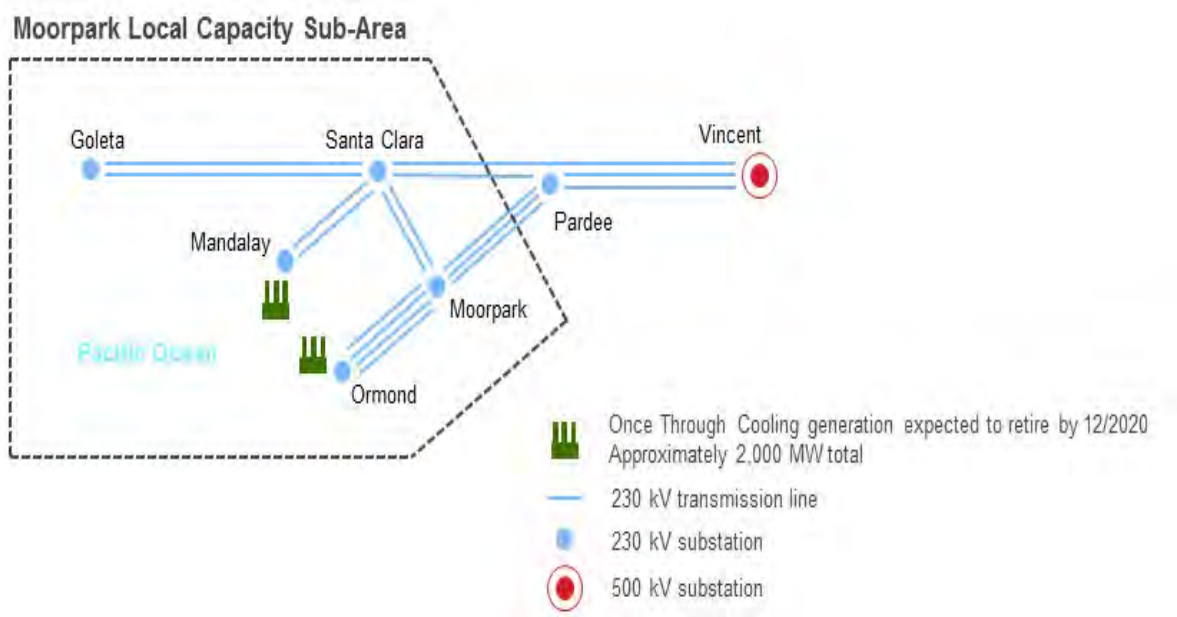
This report documents the ISO's special study of alternative resource portfolios performed for the Moorpark Sub-Area in accordance with the CEC-specified parameters and assumptions.

2.2. Overview of the Moorpark Local Capacity Sub-Area

An overview of the Moorpark local capacity Sub-Area is shown in Figure 2-1. The forecasted 2022 Moorpark Sub-Area peak load is 1723 MW.[9] This value includes 72 MW of Additional Achievable Energy Efficiency (AAEE) and the impact of 239 MW of behind-the-meter solar photovoltaic generation (BTM PV). Details about the load forecast are presented in Section 3.2.

Figure 2-1

Overview of the Moorpark Sub-Area



[8] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=7DFD7E72-8C3C-4BD5-9615-3313D0DBE22C.

[9] See http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/LSE-BA_Forecasts.php, re-posted on February 27, 2017.

Table 2-1 provides the net qualifying capacity (NQC) of resources expected to be available in the Moorpark Sub-Area in the post 2020 period.

Table 2-1

Available Resources in the Post 2020 Period

Existing generation	2336 MW
Expected Retirements including Mandalay 3	(2076 MW)
Existing and approved preferred resources	30 MW
Available resources in the post 2020 period	**290 MW**

2.3. Current Projection of Local Capacity Requirements

The applicable reliability criteria provide that the most critical contingency in a local area establishes the minimum local capacity requirements. In the Moorpark sub-area, the most critical contingency that sets the minimum local capacity requirements is the loss of the Moorpark–Pardee #3 230 kV line followed by the loss of the Moorpark–Pardee #1 and #2 230 kV lines, which causes voltage collapse. Voltage collapse is not allowed under such a contingency event based on the applicable planning standards.[10] The most recent California ISO LCR study; i.e., the 2022 Local Capacity Technical Analysis, established an LCR of 554 MW for the Moorpark Sub-Area.[11] Absent Puente and Mandalay Generating Station Unit 3 (Mandalay 3), there will be a 264 MW local capacity deficiency by 2022 in the Moorpark area as shown in Table 2-2. If Mandalay 3 remains in service, the local capacity requirement deficiency in the Moorpark sub-area would be reduced by 130 MW in the near term.[12]

[10] ISO Tariff Section 40.3.1.1(2).

[11] http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf, at Page 61.

[12] The default assumption in long term planning studies for Mandalay 3, which is currently 47 years old, is and has been that it would be retired in accordance with the CPUC 2017 Assumptions and Scenario for Long-Term Planning (Draft) which states: Retirement assumptions are also based on facility age as a proxy for determining a facility's operational life. Similarly to renewable and hydro retirement assumptions, the operational history of non-renewable/hydro facilities will not be considered in this planning cycle. A “Low” level of retirement assumes that “Other” resource types stay online unless there is an announced retirement date. A “Mid” level assumes a retirement schedule based on resource age of 40 years or more. A “High” level assumes a retirement schedule based on resource age of 25 years or more. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the “Mid” level that has a three year contract should be assumed to retire at 41 years once that contract expires. Commission staff will periodically request confidential procurement data from the utilities to screen for such facilities. “Other” includes all resources whose retirement assumptions are not explicitly described

Table 2-2

Projected Moorpark Sub-Area Local Capacity Deficiency[13]

2022 LCR	554 MW
Available resources in the post 2020 period	290 MW
Deficiency	**264 MW**

3. Input Data and Assumptions

3.1. Resource Portfolio and Scenarios Evaluated

In accordance with the parameters and assumptions the CEC specified, the ISO collaborated with SCE to develop a base set of incremental distributed resources to be coupled with large scale IFOM battery storage and/or a dynamic reactive power device to meet local capacity requirements consistent with the applicable reliability criteria.[14] This study assessed the capacity and duration of the IFOM battery storage or dynamic reactive power support needed, in addition to the base set of incremental distributed resources, to meet the applicable reliability criteria. The base set of incremental distributed resources assumed in the study is described in Table 3-1.

above - for example, peaker and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

[13] The MW amount of resources needed to fill the local capacity deficiency is dependent on a number of factors including location, reactive power capability and output characteristics of the resources.

[14] The resource portfolio and scenarios were presented during a stakeholder call on June 30, 2017.

Table 3-1

Base Incremental Distributed Resource Assumptions[15]

Resource	Capacity (MW)	Output Duration	Assumed Location
Demand response (load reduction/BTM energy storage)	80 MW	4-hr	Distributed among three substations in proportion to load
PV solar/energy storage hybrid	25 MW	7-hr (2.5-hr energy storage)	
Storage enabled existing slow-responding demand response (DR)(1)	~ 30 MW	6-hr (0.5-hr storage)	Existing DR location
Base Incremental Distributed Resource Portfolio total	**135 MW**		

(1) This resource represents existing slow DR which would be coupled with energy storage to increase speed of response and thereby reduce frequency of calls.

After establishing the base incremental distributed resource portfolio, the study evaluated the following three scenarios to determine local capacity requirements consistent with the local capacity technical study criteria:

- **Scenario 1 –** Grid connected IFOM battery storage with typical reactive power capability located near Mandalay;
- **Scenario 2 –** A 240 Mvar dynamic reactive power device plus grid connected battery storage as needed; and
- **Scenario 3 –** Grid connected IFOM battery storage with typical reactive power capability located near Mandalay and Goleta, assuming the Ellwood Generating Station (Ellwood) is retired to account for the current uncertainty regarding the long-term availability of Ellwood.[16]

[15] The incremental distributed resource resources portfolio identified by SCE included 15 MW of energy efficiency (EE). Since the CEC 2017-2027 load forecast already includes up to 111 MW of additional achievable energy efficiency (AAEE) in the Moorpark Sub-Area, the 15 MW of EE is assumed to contribute towards the AAEE that is embedded in the load forecast and is therefore not modeled in addition to the 111 MW.

[16] The Ellwood facility currently counts toward identified LCR needs in the Moorpark sub-area. The CPUC is currently considering whether to accept a refurbishment contract to ensure that the Ellwood facility remains operational. The CPUC's current Proposed Decision rejects the Ellwood refurbishment contract (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M183/K389/183389354.PDF).

The ISO modeled resources that incorporate reactive power capability with that capability in testing their adequacy to meet system needs. As the voltage stability concerns primarily establish the requirements for additional resources, both real and reactive power supply in the area play a role in supporting reliability, with the real power being generally more effective than reactive power and both real and reactive power required simultaneously. For example, the Puente plant is expected to provide 262 MW of real power and a minimum reactive power range of 130 Mvar lagging to 88 Mvar leading, meeting the ISO tariff requirement for synchronous generation to provide a reactive power range of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) measured at the generator terminals.

When modeling grid connected storage with inverter technology, the ISO modeled those facilities using the range of reactive power support required by the ISO tariff, as that would be the minimum requirement from those asynchronous facilities as a condition of interconnection to the grid. The ISO tariff requirement is 0.95 leading to 0.95 lagging power factor measured at the high side of the generator substation.

In Scenario 2, the ISO tested the effectiveness of additional reactive support by modeling a 240 Mvar reactive support device in the area. This reactive support was incremental to the reactive support provided by other devices. However, this reactive support could be provided by increasing the capacity of the inverters at battery storage facilities to increase the reactive output capability of the inverter while also delivering the required MW output, to provide incremental reactive support beyond the minimum requirement for asynchronous generators. The 240 Mvar assumption was based on both (1) the range of dynamic reactive support provided by other projects recently moving forward in the ISO footprint, the majority of which are synchronous condensers, and (2) being a material but not excessive amount to model to reasonably demonstrate the impact of dynamic reactive support in offsetting other mitigations. The study results are independent of the actual source of reactive power support being provided.

3.2. Forecast Peak and Hourly Load

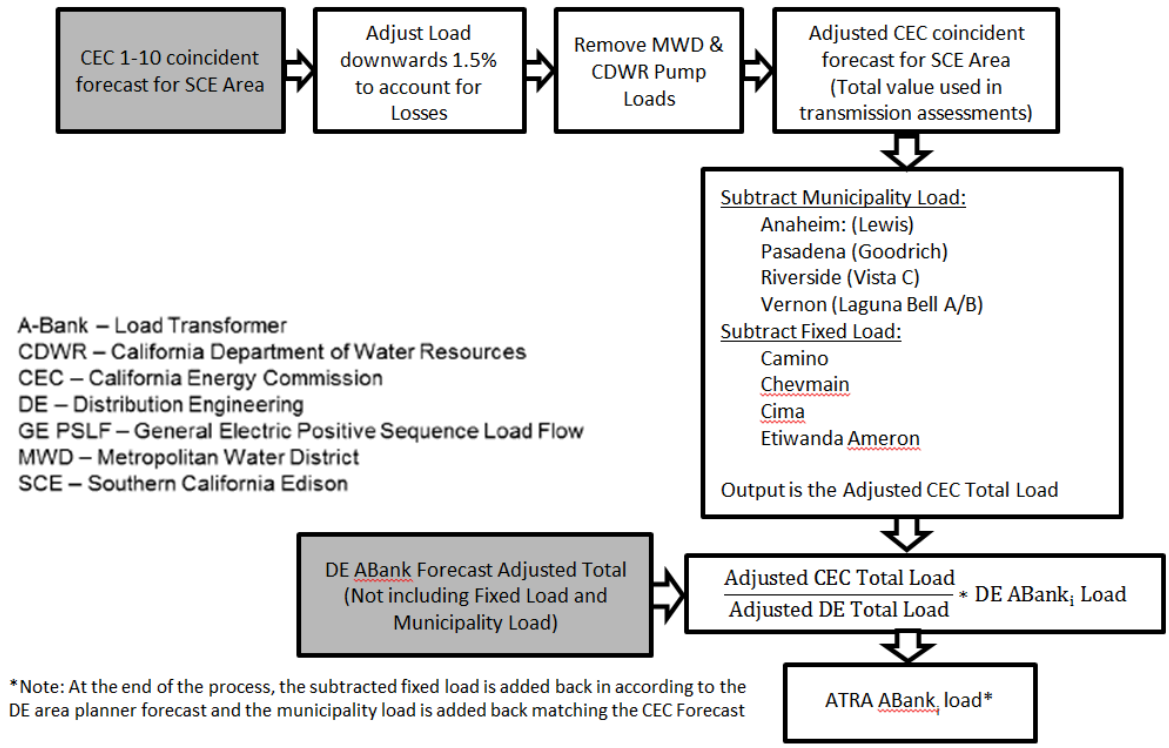
As noted above, the forecasted 1-in-10 year 2022 Moorpark Sub-Area peak load is 1723 MW, which includes 72 MW of Additional Achievable Energy Efficiency (AAEE) and the impact of 239 MW of installed behind-the-meter solar photovoltaic generation (BTM PV).[17] The load forecast is based on the California Energy Demand Updated Forecast for 2017-2027 as developed by the CEC; specifically the mid-demand baseline

[17] BTM PV information is based on the amount the CEC provided for Big Creek West Zone. http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf, Table 4.6-2, Page 19.

with low-mid AAEE.[18] This forecast is consistent with load forecasts used in the CPUC's long-term procurement plan and annual resource adequacy proceedings. Because CEC load forecasts provide aggregated information for an area larger than the Moorpark sub-area, the ISO relies on participating transmission owners (PTOs), in this case SCE, to allocate the CEC forecast to individual load-serving substations and local areas. Figure 3-1 identifies the steps SCE follows to allocate the forecast aggregate CEC load among its load-serving substations. As recommended by the CEC for evaluating previously approved projects, the peak load value for Moorpark Sub-Area includes an estimated peak-shift adjustment of about 53 MW.[19]

Figure 3-1

SCE Load Forecast Allocation Methodology



In addition to forecasted peak load, SCE provided projected hourly load data for 2022 for the study. The ISO used three hourly load shapes for 2022, all of which were derived

[18] See http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/LSE-BA_Forecasts.php, re-posted on February 27, 2017.

[19] The estimate of peak-shift adjustment for the Moorpark Sub-Area is based on data provided by the CEC for Big Creek West Zone. See http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf, Section 4.6-4, Pages 18-20.

by scaling recorded area load for historical years 2014, 2015 and 2016 to match the forecast 2022 1-in-10 year peak area load. Table 3-2 provides the Moorpark Sub-Area hourly recorded and projected load for the respective peak day.

Table 3-2

Moorpark Sub-Area Hourly Load Forecast for Year 2022

Hour	Moorpark Sub-Area Recorded Hourly Load (MW) (Note 1)			Moorpark Sub-Area Forecast Hourly Load for Year 2022 (MW)		
	Year 2014	Year 2015	Year 2016	Scaled from 2014	Scaled from 2015	Scaled from 2016
0	910.8	874.0	738.6	1024.4	970.0	867.1
1	844.7	812.7	684.9	950.1	902.0	804.1
2	805.0	768.6	650.3	905.4	853.1	763.4
3	774.9	749.8	633.1	871.6	832.2	743.3
4	761.3	739.5	629.6	856.2	820.8	739.2
5	773.5	755.0	652.3	870.0	837.9	765.9
6	841.3	817.8	709.2	946.2	907.7	832.7
7	921.5	900.8	784.2	1036.4	999.8	920.7
8	1000.2	978.3	846.0	1124.9	1085.8	993.2
9	1092.9	1088.5	943.6	1229.1	1208.1	1107.8
10	1203.6	1207.3	1035.5	1353.6	1339.9	1215.8
11	1306.7	1315.6	1124.7	1469.7	1460.2	1320.4
12	1384.5	1389.6	1207.3	1557.1	1542.3	1417.4
13	1444.3	1457.9	1300.1	1624.4	1618.1	1526.4
14	1494.2	1501.1	1366.4	1680.5	1666.0	1604.2
15	1525.6	1530.7	1418.4	1715.8	1698.8	1665.2
16	1531.5	1552.0	1464.7	1722.5	1722.5	1719.6
17	1504.1	1551.5	1467.2	1691.6	1721.9	1722.5
18	1447.8	1484.0	1423.3	1628.3	1647.1	1671.0
19	1418.3	1424.1	1353.7	1595.1	1580.6	1589.3
20	1418.4	1434.4	1316.8	1595.2	1592.0	1546.0
21	1329.4	1359.7	1220.0	1495.2	1509.1	1432.3
22	1186.0	1225.5	1077.4	1333.9	1360.2	1264.9
23	1037.3	1045.2	933.1	1166.7	1160.0	1095.5

Note 1 - The 2014, 2015, and 2016 peak loads for the Moorpark Sub-Area occurred on 9/15/2014, 9/9/2015 and 9/26/2016, respectively.

While this study was in progress it was discovered that the recorded load data was impacted by actual demand response calls. This means that some of the existing demand response was double counted when it was again used as a resource in the load and resource analysis. The information obtained from SCE, which is provided in Table 3-3, was not available in time for consideration in the analysis and therefore was not reflected in this analysis. Consequently, the results presented in this study tend to slightly underestimate the actual local capacity requirement need, but are not expected to materially alter the results.

Table 3-3

Amount of Double-Counted Existing Demand Response

	Demand Response called (MW)		
HE	9/16/2014	9/9/2015	9/26/2016
15	5.4	0.7	0.0
16	13.0	2.3	0.8
17	14.1	2.3	1.4
18	13.5	2.4	1.1
19	7.7	2.3	0.6

3.3. Preferred Resource and Storage Hourly Output Characteristics

The ISO used the output characteristics of preferred resources and storage summarized in Table 3-4 in the hourly load and resource analysis. For the previously authorized PV resources (5.7 MW), the ISO used available CEC hourly PV output data for a typical peak day (Sept 26, 2022) for Big Creek West Zone to calculate the hourly output. The ISO used the same CEC hourly PV output data to derive the duration of the energy storage component of the PV/energy storage hybrid resource included in the base incremental distributed resource portfolio.[20] A battery storage unit is assumed to take 1.2 times as long to charge as it does to discharge per ISO 2017-2018 Transmission Planning Process Unified Planning Assumptions and Study Plan.[21]

[20] As described in Section 3.1 above, the PV solar/energy storage hybrid distributed energy resources is designed to have a 25 MW capacity and 7-hour duration.

[21] *See* http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf, Table 4.8-5, Page 35.

Table 3-4

Hourly Characteristics of Preferred Resources and Energy Storage

Resource	Capacity (MW)	Output characteristics/duration	Charging duration (battery storage)
Solar PV (Procurement approved in CPUC Decision 16-05-050)	5.7 MW (NQC)	Hourly profile	N/A
EE (Procurement approved in CPUC Decision 16-05-050)	6 MW	Full output during hours 13-21, variable in proportion to load outside those hours	N/A
Existing fast DR	18.1 MW	6 hours	N/A
Demand response (load reduction/BTM energy storage)	80 MW	4 hours	~5 hours
PV solar/energy storage hybrid	25 MW	7 hours	~3 hours
Storage enabled existing slow-responding demand response (DR)	30 MW	6-hr	~ 1 hour
IFOM battery storage – Scenario 1	TBD	TBD (initial: 4 hours)	TBD (initial: ~5 hours)
IFOM battery storage – Scenario 2	TBD		
IFOM battery storage – Scenario 3	TBD		

3.4. Voltage Stability Area Load Limit

The voltage stability area load limit for the Moorpark area for the critical contingency is determined using the Power-Voltage (P-V) method. In this method the load in the area is increased in small increments until the power flow solution diverges. The analysis is performed with all variable and runtime limited resources excluded in order to determine the limit that dictates dispatch of runtime-limited dispatchable resources and enables accounting for the variability in output of non-dispatchable intermittent resources. The dynamic reactive power device is modeled online in Scenario 2 whereas the Ellwood facility is removed from service in Scenario 3.

Figure 3-2 provides the resulting P-V curves for the three scenarios under the critical contingency with preferred resources and energy storage excluded. In all three scenarios, voltage collapse occurs when the area load is below the forecast peak area load of 1723 MW. The local capacity resources must be dispatched whenever area load exceeds the voltage stability limit. Figure 3-3 shows the area load limit against the area load shapes for the five days around the peak day.

Figure 3-2

Determination of Voltage Stability Area Load Limit

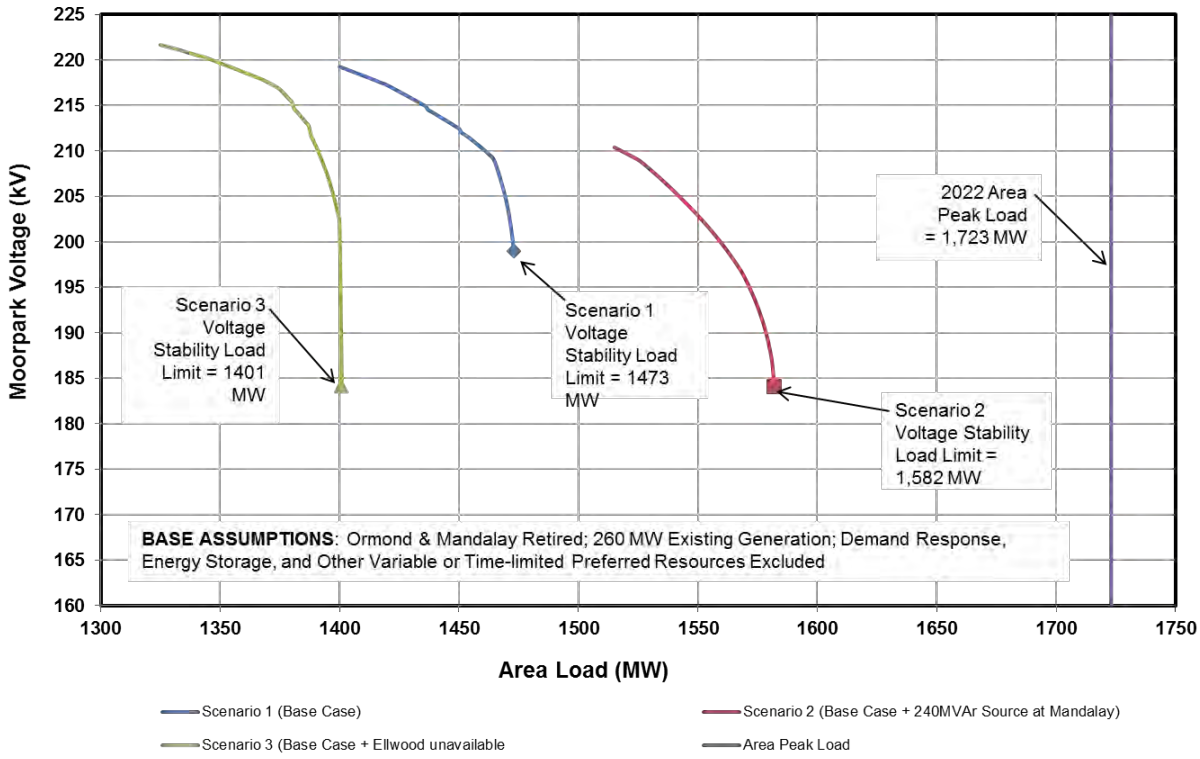
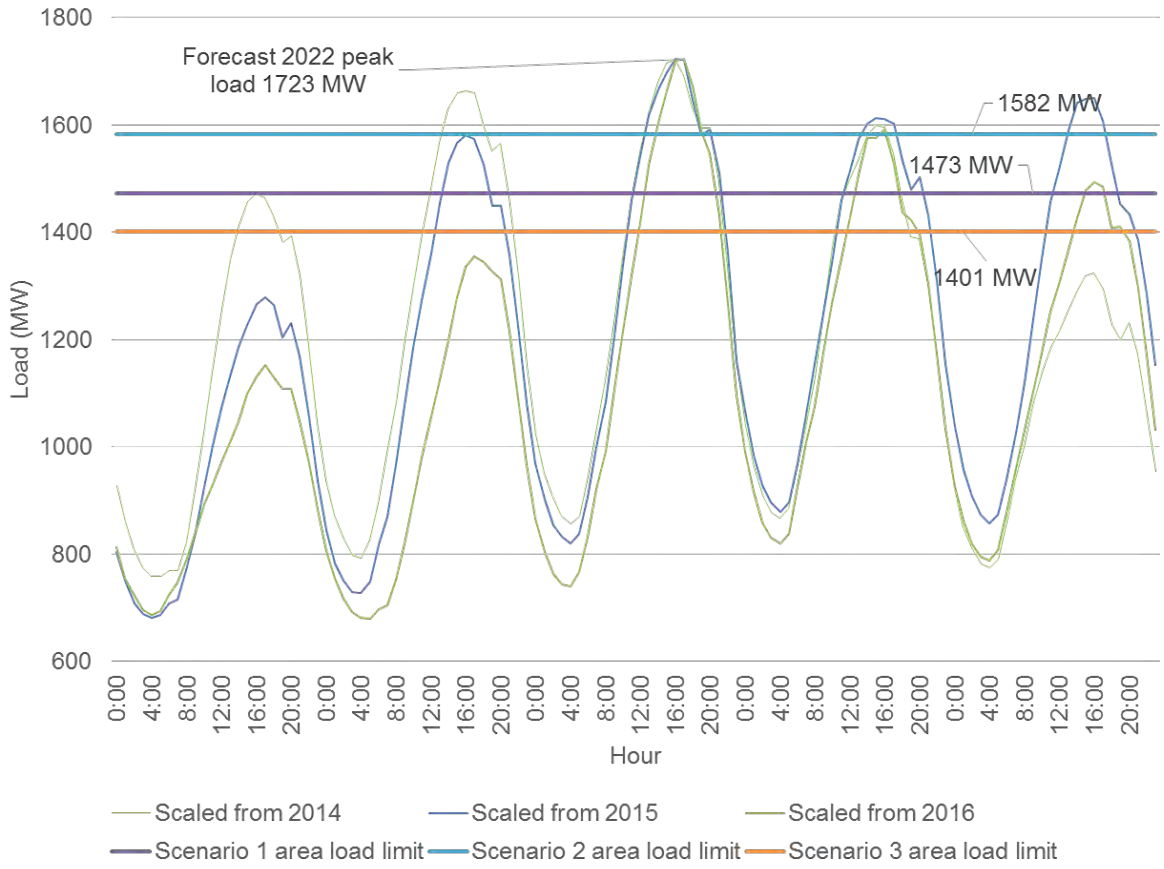


Figure 3-3

Hourly Area load and Voltage Stability Limit



4. Study Methodology and Results

The study is based on power flow analysis coupled with a spreadsheet evaluation of hourly load and resource output. The latter takes into account hourly variation of area load and output of resources such as PV, energy or runtime limitation of resources such as demand response and energy storage, and availability of time windows for energy storage charging, when it acts as load.

The methodology has three parts which were performed for each of the three scenarios and three area load shapes.

Step 1 – Derive an initial estimate of storage battery capacity (MW) for use in the hourly load and resource analysis using power flow analysis of the peak load hour assuming all resources, including runtime limited resources, are online.

Step 2 – Perform hourly load and resource analysis to assess the storage battery duration needed, test and adjust storage battery capacity as needed, and evaluate ability to fully recharge for next day duty.

Step 3 – Validate the hourly load and resource dispatch from previous step using power flow analysis and adjust storage capacity or duration as needed

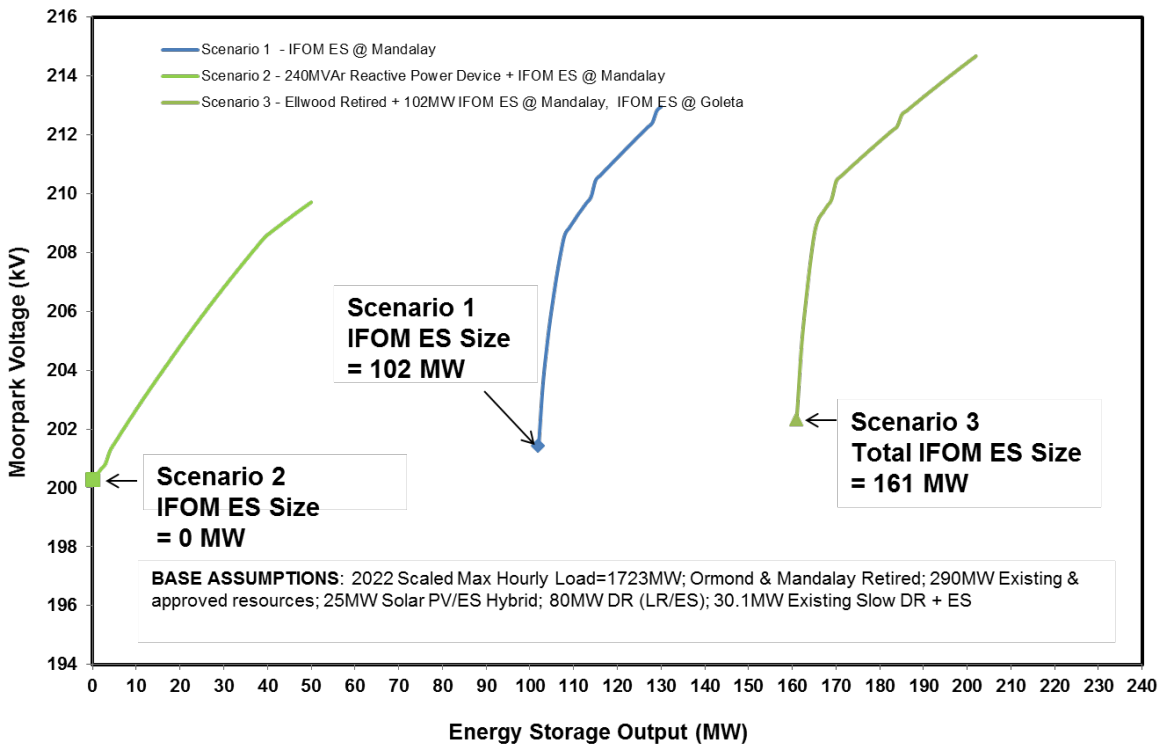
The details of each step including methodology and results are presented in the next sections.

4.1. Determination of Initial Battery Storage Capacity

Step 1 involved performing power flow analysis for the peak load hour using the 2022 summer peak LCR base case as a starting point with the critical contingency applied. The analysis is performed assuming all available resources including energy and run-time limited resources are online. The battery storage MW output and Mvar capability range is decreased in small decrements until the voltage stability point is reached as shown in Figure 4-1.

Figure 4-1

Determination of Initial Battery Storage Capacity



Based on the above results, the battery storage sizes identified in Table 4-1 were used as the initial values for the hourly load and resource analysis and were subject to adjustment as needed based on the results of subsequent steps.

Table 4-1

Initial Battery Storage Capacity

Scenario	Minimum Storage Capacity	Block Sizes Assumed
Scenario 1	102 MW	1x55 MW, 1x50 MW
Scenario 2	0	N/A
Scenario 3	161 MW	1x55 MW, 1x50 MW 1x60 MW

4.2. Hourly Load and Resource Analysis

In Step 2, the ISO performed a spreadsheet analysis of peak day and next day requirements based on an hour-by-hour accounting of area load, resources, and imports. This step is necessary because the available resources considered in this study cannot run continuously during every hour of the day. When resources such as demand response, energy storage, solar PV and other hourly limited or variable resources are considered to fill local capacity need, as is the case here, the ISO must ensure that there are sufficient local resources during each hour of the day to meet applicable reliability criteria. The analysis involved:

- Comparing the voltage stability area load limit derived using power flow analysis excluding all variable and time-limited resources with;
- The net hourly area load obtained by subtracting from area load the hourly output of all available non-dispatchable resources; and
- Dispatching sufficient dispatchable resources whenever the net load for a given hour is greater than the load limit, recognizing all resources must be dispatched at the peak load hour and that demand response is to be used last.

Energy storage resources must be charged when area load is sufficiently below the voltage stability area load limit so that the charging load plus area load does not exceed the area load limit. In general, if the area load shape is relatively flat or if the amount of energy storage dependent local capacity resources is too large for the area, there will be times when the resources do not have adequate window to sufficiently recharge

between discharging duties without violating the area load limit. The analysis performed includes assessment of the ability of energy storage resources to fully recharge for next day duty.

The hourly load and resource analysis initially assumed a four hour duration for the IFOM battery storage units determined in the previous step. The duration and in some cases the capacity is increased until the hour-by-hour requirement is met. As noted earlier, the ISO performed the analysis for each scenario and load shape. Results for up to three iterative steps for each case are provided in this report to demonstrate the need for each increase in battery storage duration or capacity.

As an example, the ISO provided the hour-by-hour analysis for Scenario 1 using the 2014 load shape in Table 4-2. The analysis for each of the scenarios and load shapes is provided in Appendix A. The first iteration of the load and resource analysis (shown in the first worksheet below) is based on a four-hour battery storage duration and indicates a local capacity deficiency for a total of seven hours. In this case, no deficiency was identified during the hours of battery charging. The second iteration of the load and resource analysis presented in the second worksheet, which is performed with a battery storage duration of nine hours, does not show a local capacity MW deficiency as can be seen from the values in the third row from last. The last two rows of the worksheet are related to the results of the power flow validation step and are discussed in the next section.

Table 4-2

Hourly Analysis Example for Scenario 1 with 2014 Load Shape

Table A-1a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2014 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit & One 55 MW, 4 hr IFOM Battery Unit

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(13.3)	73.3	140.0	196.3	232.5	240.5	211.2	149.2	116.1	116.2	16.2	(143.7)	(310.4)	(437.5)	(512.5)	(565.5)	(598.8)	(609.0)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	258.7	0.0	0.0	50.0	130.5	178.7	258.7	208.7	153.2	153.2	73.2	0.0	0.0	0.0	(240.6)	(210.5)	(210.5)	(185.5)	(185.5)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		(13.3)	73.3	90.0	65.8	53.8	(18.2)	2.5	(4.0)	(37.1)	43.0	16.2	(143.7)	(310.4)	(196.9)	(302.0)	(355.0)	(413.3)	(423.5)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)

Table A-1b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2014 Load Shape, Iteration 2 - Two 55 MW, 9 hr IFOM Battery Units

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(13.3)	73.3	140.0	196.3	232.5	240.5	211.2	149.2	116.1	116.2	16.2	(143.7)	(310.4)	(437.5)	(512.5)	(565.5)	(598.8)	(609.0)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
IFOM ES Block 2 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	263.7	0.0	80.0	153.1	233.1	263.2	263.2	263.2	183.2	140.1	140.1	55.0	0.0	(110.0)	(245.1)	(215.0)	(215.0)	(190.0)	(190.0)	(110.0)	(110.0)	(110.0)	(110.0)	(110.0)	0.0
Local Capacity Deficiency (Note 3)		(13.3)	(6.7)	(13.1)	(36.8)	(30.7)	(22.7)	(52.0)	(34.0)	(24.0)	(23.9)	(38.8)	(143.7)	(200.4)	(192.4)	(297.5)	(350.5)	(408.8)	(419.0)	(481.7)	(405.6)	(322.3)	(236.8)	(113.4)	(110.3)
Power Flow Dispatch Validation (Note 5)				Failed																					
Incremental ES Capacity Required (Note 6)				5.0																					

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

4.3. Validation of Hourly Results in Power Flow

In Step 3, the ISO validated the hourly results derived in Step 2 based on power flow modeling. This step is necessary because the spreadsheet load and resource analysis described in the preceding section does not consider reactive power and locational impacts. In this step, the ISO modeled the load and resource dispatch for each hour of the 24-hour period obtained from the hourly load and resource analysis in the power flow model to confirm that the dispatch yielded stable voltages. If the dispatch in any hour failed to yield stable voltages, the ISO increased battery storage capacity until valid results are obtained. The results of this step are provided in the last two rows of the second worksheet presented in Table 4-2 above. The results show which hour (or hours) failed the validation. In the case, the validation failed in hour 13, and the incremental increase in battery storage capacity was 5 MW. In this case, no validation failed due to energy storage charging.

Step 3 establishes the final capacity and duration of battery storage that is necessary to meet local capacity requirements in addition to the base incremental distributed resource portfolio described above.

4.4. Summary of Study Results

4.4.1. Results for Scenario 1

Step 1 (Section 4.1) established an initial need for 102 MW of grid-connected energy storage resources for Scenario 1 that the ISO modeled in one 55 MW block and one 50 MW block both of which were initially modeled with a four-hour duration along with the base incremental 135 MW distributed resource portfolio. The Step 2 analysis indicated that limiting the battery storage duration capability to four hours resulted in local capacity deficiencies for up to a total of seven hours with a maximum deficiency of 134 MW during Hour 13 (based on the 2015 load shape). The duration of battery storage units needed to be increased to 9 hours in Iteration 2 to achieve a dispatch in which none of the hours showed any deficiency. The capacity of one unit was also increased by 5 MW to address a deficiency that would otherwise occur on Hour 13 in the analysis performed with the 2015 load shape. Despite these increases, the results of the Step 3 power flow validation for Hour 13 in the case of the 2014 load shape and Hour 13 and 18 in the case of the 2015 load shape failed to yield stable voltages, causing the respective battery storage capacity to be further increased by up to 15 MW. Table 4-3 provides a summary of the results for Scenario 1 for the three load shapes considered. Detailed results are provided in Appendix A, Table A-1 thru Table A-3.

Based on the results, the recommended capacity and duration for the Mandalay battery storage for Scenario 1 are:

- One 65 MW / nine-hour duration
- One 60 MW / nine-hour duration

Table 4-3

Scenario 1 Results Summary

Description	**2022 hourly load based on:**					
	2014		2015		2016	
	Iteration step					
	1	2	1	2	1	2
Mandalay ES Block 1 - Capacity (MW)	50	55	50	55	50	55
Mandalay ES Block 1 - Duration (hours)	4	9	4	9	4	7
Mandalay ES Block 2 - Capacity (MW)	55	55	55	55	55	55
Mandalay ES Block 2 - Duration (hours)	4	9	4	9	4	4
Total number of hours with remaining local capacity deficiency	7	0	6	0	3	0
Total number of hours failing power flow validation (hours)	Note 1	1	Note 1	2	Note 1	0
Incremental battery storage capacity required in Step 3 to mitigate power flow failure (MW)		5		15		0
Note 1 – The power flow dispatch validation was only performed on iterations that didn't include a local capacity MW deficiency in the Step 2 analysis						

4.4.2. Results for Scenario 2

For Scenario 2, a 240 Mvar reactive power device near Mandalay along with the base incremental 135 MW distributed resource portfolio was considered. The hourly load and resource analysis conducted for this scenario did not indicate any deficiency and none of the hours failed the Step 3 power flow validation. As a result, no grid connected battery storage was found to be needed in addition to the 240 Mvar reactive power device and the base incremental distributed resource portfolio.

In addition, the hourly load and resource analysis showed a local capacity margin as low as 12 MW, which indicates the size of the reactive power device is reasonable. Table 4-4 provides a summary of the results for Scenario 2. Detailed results are provided in Appendix A, Table A-4 thru Table A-6.

Table 4-4

Scenario 2 Results Summary

Description	2022 hourly load based on:					
	2014		2015		2016	
	Iteration step					
	1	2	1	2	1	2
Mandalay ES Block 1 - Capacity (MW)	0	--	0	--	0	--
Mandalay ES Block 1 - Duration (hours)	0	--	0	--	0	--
Mandalay ES Block 2 - Capacity (MW)	0	--	0	--	0	--
Mandalay ES Block 2 - Duration (hours)	0	--	0	--	0	--
Total number of hours with remaining local capacity deficiency	0	--	0	--	0	--
Total number of hours failing power flow validation (hours)	0	--	0	--	0	--
Incremental battery storage capacity required to mitigate power flow failure (MW)	0	--	0	--	0	--

Unlike Scenario 1 and 3 and the Puente option, the reactive support does not help in reducing loss of load through load shedding to avoid thermal overloads; load shedding is not desirable but is permitted under the local capacity technical study criteria in the circumstances and limiting contingencies being studied.

4.4.3. Results for Scenario 3

Step 1 (Section 4.1) established a need for 162 MW of grid-connected energy storage resources for Scenario 3 that the ISO modeled in one 60 MW block, one 55 MW block and one 50 MW block along with the base incremental 135 MW distributed resource portfolio. In the first iteration the ISO performed as part of its Step 2 analysis a 4 hour duration was considered. The hourly load and resource analysis results for this iteration using the 2014 load shape indicated local capacity deficiency for nine of the hours evaluated. In Iteration 2, the duration of battery storage units needed to be increased to nine hours for one Mandalay unit and to ten hours for the remaining two units in order to achieve a dispatch in which none of the hours showed any deficiency. Due to the large duration of the battery storage units considered, charging became an issue and, as a result, a third iteration step was conducted in which the Mandalay 10-hour duration unit was broken into two units of five-hour duration each in order to be able to recharge them simultaneously during hours of lowest load.

After all the local capacity deficiencies in the hourly load and resource worksheet were resolved, the load and resource dispatch for each hour was modeled and tested in the Step 3 power flow analysis. The results for Hour 12 failed to yield valid power flow

results causing the aggregate Mandalay battery storage capacity to be increased by 5 MW.

Similar analysis for Scenario 3 was performed using the load shapes from 2015 and 2016. *** provides a summary of the results for Scenario 3 for the three load shapes considered. Detailed results are provided in Appendix A, Table A-7 thru Table A-9.

Based on the results, the recommended capacity and duration for the battery storage units for Scenario 3 are:

- One 65 MW / nine-hour duration (Mandalay)
- One 55 MW / five-hour duration (Mandalay)
- One 60 MW / five-hour duration (Mandalay)
- One 60 MW / ten-hour duration (Goleta)

Table 4-5

Scenario 3 Results Summary

Description	**2022 hourly load based on:**							
	2014			2015			2016	
	Iteration step							
	1	2	3	1	2	3	1	2
Mandalay ES Block 1 - MW	50	55	55	50	55	55	50	55
Mandalay ES Block 1 - Hours	4	9	9	4	9	9	4	8
Mandalay ES Block 2 - MW	55	55	55	55	55	55	55	55
Mandalay ES Block 2 - Hours	4	10	5	4	10	5	4	8
Mandalay ES Block 3 - MW (Note 3)	--	--	55	--	--	55	--	--
Mandalay ES Block 3 - Hours (Note 3)	--	--	5	--	--	5	--	--
Goleta ES Block 2 - MW	60	60	60	60	60	60	60	60
Goleta ES Block 2 - Hours	4	10	10	4	10	10	4	7
Total number of hours with remaining local capacity deficiency	9	3 (Note 2)	1 (Note 4)	9	1 (Note 2)	0	8	0
Total number of hours failing power flow validation (hours)	Note 1		1	Note 1		2	Note 1	0
Incremental battery storage capacity required to mitigate power flow failure in Step 3 (MW)			5			15		0

Note 1 – The power flow dispatch validation was only performed on iterations that didn't include a local capacity MW deficiency in the Step 2 analysis
Note 2 – Some or all hours with deficiencies occurred during charging.
Note 3 – To mitigate the charging deficiency, established 3rd ES block at Mandalay.
Note 4 – Dispatch passed validation even though load-resource analysis indicates Hour 12 was deficient.

5. Capital Cost Estimates

As the ISO does not conduct resource procurement, the ISO's access to cost information is limited to publicly available sources. While the ISO initially did not include development of cost information in the original scope, very high level estimates were subsequently developed based on publicly available information to be helpful and provide a starting point for subsequent discussion in the CEC proceeding. For comparison purposes an estimate for the Puente Power Project is also included. Below are the unit costs that are used to derive the estimates. These costs represent initial installation costs; they do not include ongoing operating or maintenance costs, or replacement costs to adjust for shorter expected lifespans of some equipment versus others.

- Solar PV - $2.65 million per MW[22]
- Battery storage (Lithium-ion) - $1.94 million per MW (4-hour)[23]
- Simple cycle CT generator (Merchant) - $1.141 million/MW[24]
- 240 Mvar dynamic reactive power device - $50.1 - $100 million[25]

A very high level capital cost estimate for each resource and overall costs for each scenario are presented in Table 5-1 and Table 5-2, respectively.

[22] California Energy Commission Consultant Report - San Joaquin Valley Distributed Energy Resource Regional Assessment, Navigant Consulting, Inc., Table 29, Page 41 (July 2016).

[23] *Ibid.*

[24] California Energy Commission Draft Staff Report – Estimated Cost of New Renewable and Fossil Generation in California, Table 51, Page 138 (May 2014).

[25] The cost of the reactive device is based on the Santiago Synchronous Condenser Project as provided in SCE's Quarterly Compliance Report (July 2017).

Table 5-1

Capital Cost Estimates of Portfolio Resources

Resource	Capacity (MW)	Output Duration (hours)	Estimated cost ($million)
Demand response (load reduction/BTM storage)	80 MW	4 hours (storage)	155.2
PV solar/energy storage hybrid	25 MW	2.5 hours (storage)	96.6
Storage to enable existing slow-responding demand response	30 MW	0.5 hours (storage)	7.3
Scenario 1 - IFOM storage battery	65 MW	9 hours	283.7
	60 MW	9 hours	261.9
Scenario 2 - Reactive device	240 Mvar	Continuous	50.1-100
Scenario 3 - IFOM storage battery (if Ellwood is retired)	65 MW	9 hours	283.7
	55 MW	5 hours	133.4
	60 MW	5 hours	145.5
	60 MW	10 hours	291.1

Table 5-2

Capital Cost Estimates of Resource Portfolios

Resource	Description	Estimated cost (millions)
Scenario 1	Incremental distributed resources plus IFOM storage battery	$805
Scenario 2	Incremental distributed resources plus reactive device	$309-$359
Scenario 3	Incremental distributed resources plus IFOM battery storage (if Ellwood is retired)	$1,116
Puente Power Project	262 MW combustion turbine generator	$299

6. Stakeholder Comments

The comments received from stakeholders following the June 30, 2017 stakeholder call are summarized below, together with a brief discussion of the ISO's consideration of those comments. The presentation included a discussion of the Moorpark need, the scope of the ISO study, and draft base incremental distributed resource portfolios. Comments were received from Amber Kinetics, the City of Oxnard, Clean Coalition, Tesla Inc., and Robert Sarvey. All comments received have also been posted on the ISO's website.

Incremental Distributed Resource Assumptions:

Three parties provided numerous comments and references to other studies suggesting higher levels of incremental distributed resources – demand response, local solar projects, storage, and hybrid projects - be explored. The ISO has reviewed these comments with SCE staff, and did not consider further adjustments to the scenarios necessary. The scenarios address a range of preferred resources including storage, and as the ISO added storage as necessary until reliability requirements were achieved, adding additional scenarios with increased storage in particular is redundant given the study methodology.

Mandalay and Ellwood

Two parties proposed that the study scope expand to consider Mandalay 3 – and one further recommended the potential conversion of 1 and 2 to synchronous condensers – as a bridging solution. While "bridging scenarios" have not been developed, the ISO study has included comment on the impact of retaining Mandalay 3 and of Ellwood on the study results. As noted in the comments, continued operation of the Mandalay plant would offset other needs by 130 MW, whether as a long term or bridging means while other resources are being acquired. As the impacts of reactive power sources are addressed on a generic basis in the ISO study, no specific comment on the viability of converting Mandalay 1 and 2 into synchronous condensers has been developed nor included in the study scope.

Reactive Power from Inverters:

Three parties raised concerns that the potential for reactive support from inverters was not properly being recognized in the ISO study and recommended different study treatment, changes to cost estimating, or further research on the issue. In this report, it has been clarified that the reactive support is required at the same time as the real power requirement, so an increase in the inverter capacity would be required to provide additional reactive support above the real power support being provided. Further, inverters are modeled at the minimum reactive support required from any asynchronous generator connecting to the ISO grid, and any additional reactive support – presumably

to provide the 240 Mvar support identified in Scenario 2 – would need to be incremental to that initial requirement.

Transmission Alternatives:

One party sought to have the ISO reassess transmission alternatives in this study of preferred resources, to consider if further study on a new study plan should be undertaken. As discussed below, transmission alternatives were previously considered in earlier processes and are not within the scope of this study. Further, no new information was provided and the comment requested additional study and delay that reached beyond the study scope agreed upon with the CEC in this process focusing on preferred resources.

Transmission alternatives – including meeting the need exclusively through the use of reactive support devices – formed part of the initial consideration in the ISO's planning activities and the CPUC proceeding that led to SCE's selection of the Puente project. As such, the ISO did not offer, nor did the CEC request, specific reconsideration of transmission alternatives in the study the ISO offered to undertake on preferred resources. The context relevant to considering transmission alternatives, and the options that have been considered in the past, are summarized below.

The Ventura area load is served by five 230 kV transmission circuits, with four of these circuits emanating from Pardee 230 kV substation. A single transmission circuit contingency followed by a credible contingency of a common tower transmission outage causes a voltage collapse resulting in loss of up to 2000 MW of Ventura and Santa Barbara area load. An extended outage of Pardee substation due to an earthquake or other disaster would result in the entire Ventura and Santa Barbara area connected by a single transmission circuit coming from Vincent substation. In considering the effectiveness of the Puente project to assess the relative benefit of other mitigations, the Puente project mitigates the overlapping transmission outage and improves load serving capability during an extended outage of Pardee substation.

Transmission upgrades that would mitigate both of these reliability concerns would most likely require a new transmission line not connected to Pardee substation and would require extensive environmental permitting review process at the CPUC for greenfield construction. These options were not pursued further due to the perceived costs and siting challenges at the time.

In addition to meeting the local capacity technical study criteria set out in the ISO's FERC-approved tariff, the Puente project also provided additional reliability benefits by minimizing the need for load shedding for contingency-driven thermal overloads that the criteria did not require to be mitigated, and provided increased load serving capability under other more extreme events such as the loss of the Pardee substation. Nonetheless, lesser transmission alternatives were considered by the ISO during the

CPUC 2012 LTPP proceedings that marginally met the minimum criteria but did not provide these other reliability benefits, including reactive support options and transmission reconfiguration options.

Reactive support

The ISO considered adding a large amount of reactive support in the analysis performed for the 2012 LTPP proceeding, to reduce the local capacity requirement. (In contrast to the study conducted in this analysis considering a more modestly sized reactive support.)

This alternative - as with the modestly sized reactive support analyzed in this study - was found to significantly mitigate the voltage stability issue, but not address the thermal overload concerns. This alternative would reduce the amount of local generation needed to be dispatched to avoid voltage collapse, but load would need to be shed manually to mitigate the thermal overloads that would also occur. As noted above, the Puente project would result in 262 MW of reduced post-contingency load shedding compared to the reactive support alternative, consistent with the findings of the smaller reactive support project in this study.

Transmission Lines:

Looping in the Vincent-Santa Clara 230 kV line into the Pardee substation was considered. This would add exposure to earthquake damage to the Pardee substation resulting in the loss of all transmission into the Moorpark area. In fact SCE intentionally de-looped this line in the past specifically to reduce this exposure.

A new Pardee-Moorpark line alternative was also considered. This, as well as the reactive support alternative discussed above - would not mitigate the exposure to earthquake damage at Pardee substation. This exposure is currently mitigated by having the Mandalay and Ormond Beach generation. Puente would improve the load serving capability to the Moorpark sub-area during an extended outage of Pardee substation. Given this limitation, further investigation of the extent of the cost and siting concerns was not pursued.

Energy storage Technology:

One party provided comments on flywheel technology as a possible consideration. As the ISO's study is meant to be technology-neutral for each type of preferred resources, focusing on the characteristics and requirements as opposed to selecting the technology to provide those requirements, this material did not affect the study process.

Load Forecast:

One party questioned the load forecast citing more recent actual loads. The ISO has provided a reference for the forecast used in this study in section 2.2, and relies on CEC and utility load forecast information that takes into account varying weather conditions.

7. Conclusion

This Moorpark Sub-Area Local Capacity Alternative Study indicates that the applicable reliability criteria can be met with a combination of base incremental distributed resources and some combination of energy storage or dynamic reactive support. Table 7-1 and Table 7-2 summarize the amount of incremental distributed resources needed under any of the scenarios studied by the ISO.

Table 7-1

Base Incremental Distributed Resources

Resource	Capacity (MW)	Output Duration	Location Studied
Demand response (load reduction/BTM energy storage)	80 MW	4 hours	Distributed among three substations in proportion to load
PV solar/energy storage hybrid	25 MW	7 hours	
Storage enabled existing slow-responding demand response (DR)	30 MW	6 hours (0.5-hr storage)	Existing locations of the DR resources
Preferred resources portfolio total	**135 MW**		

The study evaluated three alternative resource scenarios designed to supplement the incremental distributed resource portfolio and meet the applicable reliability criteria. The three scenarios considered the following resource options:

- **Scenario 1 –** Grid connected battery storage with reactive power capability located near Mandalay
- **Scenario 2 –** 240 Mvar dynamic reactive power device plus grid connected battery storage as needed and
- **Scenario 3 –** Grid connected battery storage with reactive power capability located near Mandalay and Goleta assuming Ellwood is retired given the current the uncertainty regarding the long-term availability of the plant.

The main objective of the ISO's technical analysis was to assess the capacity and duration of battery storage needed taking in to account the hourly characteristics of area

load, the capability of the transmission system and the variability, runtime-limitation and charging requirements of preferred resources and storage. The analysis was performed using three forecast hourly area load shapes for year 2022 obtained from SCE and the most recent 2022 summer peak LCR base case.

The analysis yielded the following results for the capacity and duration of grid connected battery storage.

Table 7-2

Grid connected storage needed to supplement the base incremental distributed resources portfolio and meet applicable reliability criteria

Scenario	Energy Storage Capacity (MW)	Energy Storage Output Duration (hours)	Location studied
Scenario 1 - Energy Storage	65 MW	9 hours	Mandalay
	60 MW	9 hours	
Scenario 2 - 240 Mvar Dynamic Reactive Power	0 MW	--	--
Scenario 3 - Energy Storage if Ellwood Retires	65 MW	9 hours	Mandalay
	55 MW	5 hours	
	60 MW	5 hours	
	60 MW	10 hours	Goleta

In conclusion, the study results indicate that the applicable reliability criteria can be met through incremental distributed resource additions and grid connected energy storage, albeit at costs reasonably expected to be significantly higher than the Puente project. A combination of incremental distributed resources and additional reactive support can achieve the minimum performance requirements consistent with the applicable reliability criteria at approximately comparable capital costs, but at a lower level of overall reliability and flexibility due to higher levels of potential load shedding necessary to address contingency-driven thermal overloading.

Appendix A – Hourly Load and Resource Analysis Worksheets

Table A-1a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2014 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit & One 55 MW, 4 hr IFOM Battery Unit

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(13.3)	73.3	140.0	196.3	232.5	240.5	211.2	149.2	116.1	116.2	16.2	(143.7)	(310.4)	(437.5)	(512.5)	(565.5)	(598.8)	(609.0)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	258.7	0.0	0.0	50.0	130.5	178.7	258.7	208.7	153.2	153.2	73.2	0.0	0.0	0.0	(240.6)	(210.5)	(210.5)	(185.5)	(185.5)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		(13.3)	73.3	90.0	65.8	53.8	(18.2)	2.5	(4.0)	(37.1)	43.0	16.2	(143.7)	(310.4)	(196.9)	(302.0)	(355.0)	(413.3)	(423.5)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)

Table A-1b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2014 Load Shape, Iteration 2 - Two 55 MW, 9 hr IFOM Battery Units

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(13.3)	73.3	140.0	196.3	232.5	240.5	211.2	149.2	116.1	116.2	16.2	(143.7)	(310.4)	(437.5)	(512.5)	(565.5)	(598.8)	(609.0)	(591.7)	(515.6)	(432.3)	(346.8)	(223.4)	(110.3)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
IFOM ES Block 2 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	263.7	0.0	80.0	153.1	233.1	263.2	263.2	263.2	183.2	140.1	140.1	55.0	0.0	(110.0)	(245.1)	(215.0)	(215.0)	(190.0)	(190.0)	(110.0)	(110.0)	(110.0)	(110.0)	(110.0)	0.0
Local Capacity Deficiency (Note 3)		(13.3)	(6.7)	(13.1)	(36.8)	(30.7)	(22.7)	(52.0)	(34.0)	(24.0)	(23.9)	(38.8)	(143.7)	(200.4)	(192.4)	(297.5)	(350.5)	(408.8)	(419.0)	(481.7)	(405.6)	(322.3)	(236.8)	(113.4)	(110.3)
Power Flow Dispatch Validation (Note 5)				Failed																					
Incremental ES Capacity Required (Note 6)				5.0																					

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-2a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2015 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit & One 55 MW, 4 hr IFOM Battery Unit

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(22.7)	58.5	133.7	181.8	215.5	240.5	241.5	168.0	101.6	113.0	30.1	(117.5)	(317.0)	(409.0)	(492.6)	(547.0)	(580.1)	(597.4)	(580.1)	(507.8)	(417.2)	(323.3)	(232.6)	(139.2)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	258.7	0.0	0.0	0.0	80.5	178.7	258.7	258.7	203.2	153.2	73.2	0.0	0.0	0.0	(240.1)	(210.0)	(210.0)	(185.0)	(185.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		(22.7)	58.5	133.7	101.3	36.8	(18.2)	(17.2)	(35.2)	(51.6)	39.8	30.1	(117.5)	(317.0)	(168.9)	(282.6)	(337.0)	(395.1)	(412.4)	(580.1)	(507.8)	(417.2)	(323.3)	(232.6)	(139.2)

Table A-2b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2015 Load Shape, Iteration 2 - Two 55 MW, 9 hr IFOM Battery Units

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(22.7)	58.5	133.7	181.8	215.5	240.5	241.5	168.0	101.6	113.0	30.1	(117.5)	(317.0)	(409.0)	(492.6)	(547.0)	(580.1)	(597.4)	(580.1)	(507.8)	(417.2)	(323.3)	(232.6)	(139.2)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
IFOM ES Block 2 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	263.7	0.0	80.0	135.0	215.0	233.1	263.2	263.2	183.2	158.2	158.2	85.1	0.0	(110.0)	(245.1)	(215.0)	(215.0)	(190.0)	(190.0)	(110.0)	(110.0)	(110.0)	(110.0)	(110.0)	0.0
Local Capacity Deficiency (Note 3)		(22.7)	(21.5)	(1.3)	(33.2)	(17.6)	(22.7)	(21.7)	(15.2)	(56.6)	(45.2)	(55.0)	(117.5)	(207.0)	(163.9)	(277.6)	(332.0)	(390.1)	(407.4)	(470.1)	(397.8)	(307.2)	(213.3)	(122.6)	(139.2)
Power Flow Dispatch Validation (Note 5)				Failed					Failed																
Incremental ES Capacity Required (Note 6)				15.0					5.0																

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-3a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2016 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit & One 55 MW, 4 hr IFOM Battery Unit

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1320	1417	1526	1604	1665	1720	1723	1671	1589	1546	1432	1265	1095	991	916	860	831	819	838	927	1008	1077	1176	1268
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	4.6	4.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.4	3.8	3.5	3.2	3.0	2.9	2.9	2.9	3.2	3.5	3.8	4.1	4.4
Load less LTPP PV & EE		1311.0	1407.1	1515.0	1593.0	1654.9	1710.6	1715.1	1664.9	1583.3	1540.0	1426.3	1260.5	1091.7	987.3	912.5	856.9	827.7	816.4	834.7	923.9	1004.6	1071.5	1168.8	1258.8
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(162.0)	(65.9)	42.0	120.0	181.9	237.6	242.1	191.9	110.3	67.0	(46.7)	(212.5)	(381.3)	(485.7)	(560.5)	(616.1)	(645.3)	(656.6)	(638.3)	(549.1)	(468.4)	(401.5)	(304.2)	(214.2)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	258.7	0.0	0.0	50.0	130.5	178.7	258.7	208.7	153.2	153.2	73.2	0.0	0.0	0.0	(240.1)	(210.0)	(210.0)	(185.0)	(185.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		(162.0)	(65.9)	(8.0)	(10.5)	3.2	(21.1)	33.4	38.7	(42.9)	(6.2)	(46.7)	(212.5)	(381.3)	(245.6)	(350.5)	(406.1)	(460.3)	(471.6)	(638.3)	(549.1)	(468.4)	(401.5)	(304.2)	(214.2)

Table A-3b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 1, 2016 Load Shape, Iteration 2 - One 55 MW, 7 hr IFOM Battery Unit & One 55 MW, 4 hr IFOM Battery Unit

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1320	1417	1526	1604	1665	1720	1723	1671	1589	1546	1432	1265	1095	991	916	860	831	819	838	927	1008	1077	1176	1268
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	4.6	4.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.4	3.8	3.5	3.2	3.0	2.9	2.9	2.9	3.2	3.5	3.8	4.1	4.4
Load less LTPP PV & EE		1311.0	1407.1	1515.0	1593.0	1654.9	1710.6	1715.1	1664.9	1583.3	1540.0	1426.3	1260.5	1091.7	987.3	912.5	856.9	827.7	816.4	834.7	923.9	1004.6	1071.5	1168.8	1258.8
Load Serving Capability	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473	1473
Remaing Load to Serve (Note 1)		(162.0)	(65.9)	42.0	120.0	181.9	237.6	242.1	191.9	110.3	67.0	(46.7)	(212.5)	(381.3)	(485.7)	(560.5)	(616.1)	(645.3)	(656.6)	(638.3)	(549.1)	(468.4)	(401.5)	(304.2)	(214.2)
IFOM ES Block 1 - 7hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	263.7	0.0	0.0	55.0	135.0	263.2	263.2	263.2	208.2	128.2	73.2	0.0	0.0	0.0	(245.1)	(215.0)	(215.0)	(190.0)	(190.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0
Local Capacity Deficiency (Note 3)		(162.0)	(65.9)	(13.0)	(15.0)	(81.3)	(25.6)	(21.1)	(16.3)	(17.9)	(6.2)	(46.7)	(212.5)	(381.3)	(240.6)	(345.5)	(401.1)	(455.3)	(466.6)	(583.3)	(494.1)	(413.4)	(346.5)	(304.2)	(214.2)
Power Flow Dispatch Validation (Note 5)																									
Incremental ES Capacity Required (Note 6)																									

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-4: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 2, 2014 Load Shape, Iteration 1 - 240 MVAR VAR Source at Mandalay

		Day 1													Day 2										
	MW	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582
Remaing Load to Serve (Note 1)		(122.3)	(35.7)	31.0	87.3	123.5	131.5	102.2	40.2	7.1	7.2	(92.8)	(252.7)	(419.4)	(546.5)	(621.5)	(674.5)	(707.8)	(718.0)	(700.7)	(624.6)	(541.3)	(455.8)	(332.4)	(219.3)
IFOM ES Block 1 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	153.7	0.0	25.0	43.1	123.1	153.2	153.2	153.2	73.2	30.1	30.1	0.0	0.0	0.0	(135.1)	(105.0)	(105.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency (Note 3)		(122.3)	(60.7)	(12.1)	(35.8)	(29.7)	(21.7)	(51.0)	(33.0)	(23.0)	(22.9)	(92.8)	(252.7)	(419.4)	(411.4)	(516.5)	(569.5)	(627.8)	(638.0)	(700.7)	(624.6)	(541.3)	(455.8)	(332.4)	(219.3)
Power Flow Dispatch Validation (Note 5)																									
Incremental ES Capacity Required (Note 6)																									

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-5: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 2, 2015 Load Shape, Iteration 1 - 240 MVAR VAR Source at Mandalay

		Day 1													Day 2										
	MW	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2022 Scaled Max Hourly Load		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582
Remaing Load to Serve (Note 1)		(131.7)	(50.5)	24.7	72.8	106.5	131.5	132.5	59.0	(7.4)	4.0	(78.9)	(226.5)	(426.0)	(518.0)	(601.6)	(656.0)	(689.1)	(706.4)	(689.1)	(616.8)	(526.2)	(432.3)	(341.6)	(248.2)
IFOM ES Block 1 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	153.7	0.0	25.0	43.1	123.1	153.2	153.2	153.2	73.2	30.1	30.1	0.0	0.0	0.0	(135.1)	(105.0)	(105.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency (Note 3)		(131.7)	(75.5)	(18.4)	(50.3)	(46.7)	(21.7)	(20.7)	(14.2)	(37.5)	(26.1)	(78.9)	(226.5)	(426.0)	(382.9)	(496.6)	(551.0)	(609.1)	(626.4)	(689.1)	(616.8)	(526.2)	(432.3)	(341.6)	(248.2)
Power Flow Dispatch Validation (Note 5)																									
Incremental ES Capacity Required (Note 6)																									

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-6: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 2, 2016 Load Shape, Iteration 1 - 240 MVAR VAR Source at Mandalay

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1320	1417	1526	1604	1665	1720	1723	1671	1589	1546	1432	1265	1095	991	916	860	831	819	838	927	1008	1077	1176	1268
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	4.6	4.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.4	3.8	3.5	3.2	3.0	2.9	2.9	2.9	3.2	3.5	3.8	4.1	4.4
Load less LTPP PV & EE		1311.0	1407.1	1515.0	1593.0	1654.9	1710.6	1715.1	1664.9	1583.3	1540.0	1426.3	1260.5	1091.7	987.3	912.5	856.9	827.7	816.4	834.7	923.9	1004.6	1071.5	1168.8	1258.8
Load Serving Capability	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582	1582
Remaing Load to Serve (Note 1)		(271.0)	(174.9)	(67.0)	11.0	72.9	128.6	133.1	82.9	1.3	(42.0)	(155.7)	(321.5)	(490.3)	(594.7)	(669.5)	(725.1)	(754.3)	(765.6)	(747.3)	(658.1)	(577.4)	(510.5)	(413.2)	(323.2)
IFOM ES Block 1 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - None		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	153.7	0.0	25.0	43.1	43.1	153.2	153.2	153.2	153.2	30.1	30.1	0.0	0.0	0.0	(135.1)	(105.0)	(105.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency (Note 3)		(271.0)	(199.9)	(110.1)	(32.1)	(80.3)	(24.6)	(20.1)	(70.3)	(28.8)	(72.1)	(155.7)	(321.5)	(490.3)	(459.6)	(564.5)	(620.1)	(674.3)	(685.6)	(747.3)	(658.1)	(577.4)	(510.5)	(413.2)	(323.2)
Power Flow Dispatch Validation (Note 5)																									
Incremental ES Capacity Required (Note 6)																									

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-7a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2014 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit; One 55 MW, 4 hr IFOM Battery Unit; One 60 MW, 4 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		58.7	145.3	212.0	268.3	304.5	312.5	283.2	221.2	188.1	188.2	88.2	(71.7)	(238.4)	(365.5)	(440.5)	(493.5)	(526.8)	(537.0)	(519.7)	(443.6)	(360.3)	(274.8)	(151.4)	(38.3)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 3 - 4hr (at Ellwood)	60.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	318.7	0.0	0.0	0.0	190.5	238.7	318.7	318.7	153.2	153.2	73.2	0.0	0.0	0.0	(300.1)	(270.0)	(270.0)	(245.0)	(245.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		58.7	145.3	212.0	77.8	65.8	(6.2)	(35.5)	68.0	34.9	115.0	88.2	(71.7)	(238.4)	(65.4)	(170.5)	(223.5)	(281.8)	(292.0)	(519.7)	(443.6)	(360.3)	(274.8)	(151.4)	(38.3)

Table A-7b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2014 Load Shape, Iteration 2 - One 55 MW, 9 hr IFOM Battery Unit; One 55 MW, 10 hr IFOM Battery Unit; One 60 MW, 10 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load - DR Called		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		58.7	145.3	212.0	268.3	304.5	312.5	283.2	221.2	188.1	188.2	88.2	(71.7)	(238.4)	(365.5)	(440.5)	(493.5)	(526.8)	(537.0)	(519.7)	(443.6)	(360.3)	(274.8)	(151.4)	(38.3)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(44.0)	0.0
IFOM ES Block 2 - 10hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)
IFOM ES Block 3 - 10hr (at Ellwood)	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	323.7	60.0	140.0	213.1	293.1	323.2	323.2	323.2	243.2	200.1	200.1	110.0	(60.0)	(170.0)	(305.1)	(275.0)	(275.0)	(250.0)	(250.0)	(170.0)	(170.0)	(170.0)	(170.0)	(159.0)	(55.0)
Local Capacity Deficiency		(1.3)	5.3	(1.1)	(24.8)	(18.7)	(10.7)	(40.0)	(22.0)	(12.0)	(11.9)	(21.8)	(11.7)	(68.4)	(60.4)	(165.5)	(218.5)	(276.8)	(287.0)	(349.7)	(273.6)	(190.3)	(104.8)	7.6	16.7

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-7c: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2014 Load Shape, Iteration 3 - One 55 MW, 9 hr IFOM Battery Unit; Two 55 MW, 5 hr IFOM Battery Unit; One 60 MW, 10 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2022 Scaled Max Hourly Load - DR Called		1470	1557	1624	1680	1716	1723	1692	1628	1595	1595	1495	1334	1167	1039	964	911	877	867	884	961	1045	1132	1257	1372
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.6	4.1	3.6	3.4	3.2	3.1	3.0	3.1	3.3	3.6	3.9	4.4	4.8
Load less LTPP PV & EE		1459.7	1546.3	1613.0	1669.3	1705.5	1713.5	1684.2	1622.2	1589.1	1589.2	1489.2	1329.3	1162.6	1035.5	960.5	907.5	874.2	864.0	881.3	957.4	1040.7	1126.2	1249.6	1362.7
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		58.7	145.3	212.0	268.3	304.5	312.5	283.2	221.2	188.1	188.2	88.2	(71.7)	(238.4)	(365.5)	(440.5)	(493.5)	(526.8)	(537.0)	(519.7)	(443.6)	(360.3)	(274.8)	(151.4)	(38.3)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(44.0)	0.0
IFOM ES Block 2 - 5hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0
IFOM ES Block 3 - 5hr (at Mandalay)	55.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0
IFOM ES Block 4 - 10hr (at Ellwood)	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	378.7	60.0	140.0	213.1	293.1	323.2	323.2	323.2	243.2	200.1	200.1	110.0	(60.0)	(115.0)	(250.1)	(220.0)	(330.0)	(305.0)	(305.0)	(225.0)	(225.0)	(225.0)	(115.0)	(104.0)	0.0
Local Capacity Deficiency		(1.3)	5.3	(1.1)	(24.8)	(18.7)	(10.7)	(40.0)	(22.0)	(12.0)	(11.9)	(21.8)	(11.7)	(123.4)	(115.4)	(220.5)	(163.5)	(221.8)	(232.0)	(294.7)	(218.6)	(135.3)	(159.8)	(47.4)	(38.3)
Power Flow Dispatch Validation (Note 5)			No Fail	Failed																					
Incremental ES Capacity Required (Note 6)			0.0	5.0																					

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & wort contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-8a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2015 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit; One 55 MW, 4 hr IFOM Battery Unit; One 60 MW, 4 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		49.3	130.5	205.7	253.8	287.5	312.5	313.5	240.0	173.6	185.0	102.1	(45.5)	(245.0)	(337.0)	(420.6)	(475.0)	(508.1)	(525.4)	(508.1)	(435.8)	(345.2)	(251.3)	(160.6)	(67.2)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 3 - 4hr (at Ellwood)	60.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	318.7	0.0	0.0	0.0	190.5	238.7	318.7	318.7	153.2	153.2	73.2	0.0	0.0	0.0	(300.1)	(270.0)	(270.0)	(245.0)	(245.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		49.3	130.5	205.7	63.3	48.8	(6.2)	(5.2)	86.8	20.4	111.8	102.1	(45.5)	(245.0)	(36.9)	(150.6)	(205.0)	(263.1)	(280.4)	(508.1)	(435.8)	(345.2)	(251.3)	(160.6)	(67.2)

Table A-8b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2015 Load Shape, Iteration 2 - One 55 MW, 9 hr IFOM Battery Unit; One 55 MW, 10 hr IFOM Battery Unit; One 60 MW, 10 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load - DR Called		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		49.3	130.5	205.7	253.8	287.5	312.5	313.5	240.0	173.6	185.0	102.1	(45.5)	(245.0)	(337.0)	(420.6)	(475.0)	(508.1)	(525.4)	(508.1)	(435.8)	(345.2)	(251.3)	(160.6)	(67.2)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(44.0)	0.0
IFOM ES Block 2 - 10hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)
IFOM ES Block 3 - 10hr (at Ellwood)	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	323.7	60.0	140.0	213.1	293.1	323.2	323.2	323.2	243.2	200.1	200.1	110.0	(60.0)	(170.0)	(305.1)	(275.0)	(275.0)	(250.0)	(250.0)	(170.0)	(170.0)	(170.0)	(170.0)	(159.0)	(55.0)
Local Capacity Deficiency		(10.7)	(9.5)	(7.4)	(39.3)	(35.7)	(10.7)	(9.7)	(3.2)	(26.5)	(15.1)	(7.9)	14.5	(75.0)	(31.9)	(145.6)	(200.0)	(258.1)	(275.4)	(338.1)	(265.8)	(175.2)	(81.3)	(1.6)	(12.2)

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-8c: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2015 Load Shape, Iteration 3 - One 55 MW, 9 hr IFOM Battery Unit; Two 55 MW, 5 hr IFOM Battery Unit; One 60 MW, 10 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2022 Scaled Max Hourly Load - DR Called		1460	1542	1618	1666	1699	1723	1722	1647	1581	1592	1509	1360	1160	1068	984	929	896	879	896	969	1060	1155	1248	1343
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	5.1	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.7	4.0	3.7	3.4	3.2	3.1	3.1	3.1	3.4	3.7	4.0	4.3	4.7
Load less LTPP PV & EE		1450.3	1531.5	1606.7	1654.8	1688.5	1713.5	1714.5	1641.0	1574.6	1586.0	1503.1	1355.5	1156.0	1064.0	980.4	926.0	892.9	875.6	892.9	965.2	1055.8	1149.7	1240.4	1333.8
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		49.3	130.5	205.7	253.8	287.5	312.5	313.5	240.0	173.6	185.0	102.1	(45.5)	(245.0)	(337.0)	(420.6)	(475.0)	(508.1)	(525.4)	(508.1)	(435.8)	(345.2)	(251.3)	(160.6)	(67.2)
IFOM ES Block 1 - 9hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(44.0)	0.0
IFOM ES Block 2 - 5hr (at Mandalay)	55.0	0.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0
IFOM ES Block 3 - 5hr (at Mandalay)	55.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0
IFOM ES Block 4 - 10hr (at Ellwood)	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	378.7	60.0	140.0	213.1	293.1	323.2	323.2	323.2	243.2	200.1	200.1	110.0	0.0	(115.0)	(250.1)	(220.0)	(330.0)	(305.0)	(305.0)	(225.0)	(225.0)	(225.0)	(115.0)	(104.0)	(60.0)
Local Capacity Deficiency		(10.7)	(9.5)	(7.4)	(39.3)	(35.7)	(10.7)	(9.7)	(3.2)	(26.5)	(15.1)	(7.9)	(45.5)	(130.0)	(86.9)	(200.6)	(145.0)	(203.1)	(220.4)	(283.1)	(210.8)	(120.2)	(136.3)	(56.6)	(7.2)
Power Flow Dispatch Validation (Note 5)									Failed			Failed													
Incremental ES Capacity Required (Note 6)									10.0			15.0													

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

Table A-9a: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2016 Load Shape, Iteration 1 - One 50 MW, 4 hr IFOM Battery Unit; One 55 MW, 4 hr IFOM Battery Unit; One 60 MW, 4 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load		1320	1417	1526	1604	1665	1720	1723	1671	1589	1546	1432	1265	1095	991	916	860	831	819	838	927	1008	1077	1176	1268
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	4.6	4.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.4	3.8	3.5	3.2	3.0	2.9	2.9	2.9	3.2	3.5	3.8	4.1	4.4
Load less LTPP PV & EE		1311.0	1407.1	1515.0	1593.0	1654.9	1710.6	1715.1	1664.9	1583.3	1540.0	1426.3	1260.5	1091.7	987.3	912.5	856.9	827.7	816.4	834.7	923.9	1004.6	1071.5	1168.8	1258.8
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		(90.0)	6.1	114.0	192.0	253.9	309.6	314.1	263.9	182.3	139.0	25.3	(140.5)	(309.3)	(413.7)	(488.5)	(544.1)	(573.3)	(584.6)	(566.3)	(477.1)	(396.4)	(329.5)	(232.2)	(142.2)
IFOM ES Block 1 - 4hr (at Mandalay)	50.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 2 - 4hr (at Mandalay)	55.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0	0.0	0.0	0.0	0.0	0.0
IFOM ES Block 3 - 4hr (at Ellwood)	60.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0	0.0	0.0	0.0	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	318.7	0.0	0.0	0.0	190.5	238.7	318.7	318.7	153.2	153.2	73.2	0.0	0.0	0.0	(300.1)	(270.0)	(270.0)	(245.0)	(245.0)	0.0	0.0	0.0	0.0	0.0	0.0
Local Capacity Deficiency		(90.0)	6.1	114.0	1.5	15.2	(9.1)	(4.6)	110.7	29.1	65.8	25.3	(140.5)	(309.3)	(113.6)	(218.5)	(274.1)	(328.3)	(339.6)	(566.3)	(477.1)	(396.4)	(329.5)	(232.2)	(142.2)

Table A-9b: 2022 Summer Peak Moorpark Sub-Area Hourly Local Load-Resource Analysis
Scenario 3, 2016 Load Shape, Iteration 2 - Two 55 MW, 8 hr IFOM Battery Unit; One 60 MW, 6 hr IFOM Battery Unit; Ellwood Plant Out-of-Service

		Day 1													Day 2										
	MW	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	7	8	9	10
2022 Scaled Max Hourly Load - DR Called		1320	1417	1526	1604	1665	1720	1723	1671	1589	1546	1432	1265	1095	991	916	860	831	819	838	927	1008	1077	1176	1268
LTPP 2012 Track 1 - Solar PV	5.7 (NQC)	4.8	5.4	5.4	5.2	4.3	3.0	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	3.1	4.3
LTPP 2012 Track 1 - EE	6.0	4.6	4.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	4.4	3.8	3.5	3.2	3.0	2.9	2.9	2.9	3.2	3.5	3.8	4.1	4.4
Load less LTPP PV & EE		1311.0	1407.1	1515.0	1593.0	1654.9	1710.6	1715.1	1664.9	1583.3	1540.0	1426.3	1260.5	1091.7	987.3	912.5	856.9	827.7	816.4	834.7	923.9	1004.6	1071.5	1168.8	1258.8
Load Serving Capability	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401	1401
Remaing Load to Serve (Note 1)		(90.0)	6.1	114.0	192.0	253.9	309.6	314.1	263.9	182.3	139.0	25.3	(140.5)	(309.3)	(413.7)	(488.5)	(544.1)	(573.3)	(584.6)	(566.3)	(477.1)	(396.4)	(329.5)	(232.2)	(142.2)
IFOM ES Block 1 - 8hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
IFOM ES Block 2 - 8hr (at Mandalay)	55.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0	0.0	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	(55.0)	0.0
IFOM ES Block 3 - 7hr (at Ellwood)	60.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0	0.0	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	(60.0)	0.0	0.0
LTPP 2012 Track 1 - IFOM Storage - 4hr	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV/ES Hybrid - 7hr (3hr Max Charge)	25.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	(25.0)	(25.0)	(25.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Fast DR - 6hr	18.1	0.0	0.0	18.1	18.1	18.1	18.1	18.1	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR (LR/ES) - 4hr	80.0	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.1	0.0	0.0	0.0	0.0	0.0	(80.0)	(80.0)	(80.0)	(80.0)	(80.0)	0.0	0.0	0.0	0.0	0.0	0.0
Existing Slow DR + ES - 6hr (0.5hr Charge)	30.1	0.0	0.0	0.0	0.0	0.0	30.1	30.1	30.1	30.1	30.1	30.1	0.0	0.0	(30.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Preferred Resources & Storage (Note 2)	323.7	0.0	25.0	153.1	213.1	293.1	323.2	323.2	323.3	200.1	200.1	30.1	0.0	0.0	(305.1)	(275.0)	(275.0)	(250.0)	(250.0)	(170.0)	(170.0)	(170.0)	(170.0)	(110.0)	0.0
Local Capacity Deficiency		(90.0)	(18.9)	(39.1)	(21.1)	(39.2)	(13.6)	(9.1)	(59.4)	(17.8)	(61.1)	(4.8)	(140.5)	(309.3)	(108.6)	(213.5)	(269.1)	(323.3)	(334.6)	(396.3)	(307.1)	(226.4)	(159.5)	(122.2)	(142.2)
Power Flow Dispatch Validation (Note 5)																									
Incremental ES Capacity Required (Note 6)																									

Notes -
1. "Remaing Load to Serve" is negative when no additional resources are necessary to serve the load and postive when additional resources are needed.
2. "Total Preferred Resources & Storage" represents the aggregate dispatch of preferred resources and ES. Negative numbers represent aggregate ES charging.
3. "Local Capacity Deficiency" represents remaining "Remaing Load to Serve" less the "Total Preferred Resources & Storage." When values are positive (**RED highlighted cells**), there is a load serving deficit.
4. The **BLUE highlighted cells** indicate an ES or preferred resource dispatch (positive number). The **GREEN highlighed cells** Indicate ES charging (negative number).
5. The load, resource dispatch & worst contingency were modeled in power flow to ensure enough resources were dispatced to adequately served the load without causing a voltage collapse. Cases that exhibited a voltage collapse were identified as "Failed".
6. "Incremental ES Capacity Required" delineates the additional IFOM ES Block capacity required to serve the load without causing a voltage collapse.

FOOTNOTE 31

September 29, 2017

California Energy Commission
Commissioner Janea Scott
Commissioner Karen Douglas
Hearing Officer Paul Kramer
1516 Ninth Street
Sacramento, CA 95814

Re: California Independent System Operator Corporation Post-Hearing Comments California Energy Commission Docket No. 15-AFC-01

Dear Commissioners Scott and Douglas and Hearing Officer Kramer:

The California Independent System Operator Corporation (CAISO) appreciates this opportunity to submit post-hearing comments regarding the Application for Certification (AFC) for the Puente Power Project (Puente Project) and the results of the CAISO's Moorpark Sub-Area Local Capacity Alternative Study (Moorpark Study).[1] The CAISO provides comments in response to issues raised regarding the Moorpark Study and potential options for meeting Moorpark sub-area local capacity requirements with preferred resource alternatives.

A. The CAISO's Moorpark Study Shows that the Preferred Resource Alternatives Are Technologically Feasible to Meet Local Capacity Requirements.

The Moorpark Study demonstrates that preferred resource alternatives are technologically feasible to meet local capacity requirements in the Moorpark sub-area. Several parties raised concerns regarding the specific resource portfolios studied by the CAISO, but these concerns do not detract from the central finding that a combination of preferred resources and/or reactive power devices can meet the local capacity requirements for the Moorpark sub-area if procured and implemented in a timely manner. Given this finding, the CAISO has not engaged in a point-by-point response to intervenor criticisms of the Moorpark Study because these issues are largely academic until an actual alternative resource portfolio is procured.

[1] The CAISO filed the Moorpark Study on August 16, 2017 and provided additional oral testimony at the California Energy Commission's (Commission) September 12, 2017 hearing on the Puente AFC. The CAISO is not a formal party to this proceeding, but wishes to comment on several issues raised in testimony responsive to the Moorpark Study. As a result, the CAISO submits these comments rather than a post-hearing brief.

The Moorpark Study establishes a baseline quantity of resources that should be targeted in any new request for offer (RFO) conducted in the Moorpark sub-area, but it did not seek to optimize the specific suite of preferred resources that should targeted in a new RFO. Should a new RFO be conducted, the CAISO can then study the actual resources procured to determine whether local capacity requirements have been met. With the baseline needs established in the Moorpark Study, no additional analysis is necessary to determine that preferred resources represent a technologically feasible solution to meet the Moorpark local capacity needs.

B. The Economic Feasibility of the Preferred Resource Alternatives Can Only Be Established Through a New RFO.

The CAISO believes that the economic feasibility of the preferred resource portfolios can only be established through a new RFO. The CAISO's Moorpark Study included a high-level capital cost comparison based on publicly available information for the portfolios studied. This comparison was not meant to substitute for a comprehensive analysis of the costs and benefits of these portfolios over the lifetime of the resources, nor does it reflect the general downward trend in preferred resource costs since the CAISO's source data was compiled.

Furthermore, the capital costs provided in the Moorpark Study do not render the preferred resource portfolios economically infeasible. An economically feasible option need not be the least expensive option, especially given the environmental and performance issues that are unique to each portfolio. A new RFO would provide an opportunity for Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) to analyze and review the net present value of the preferred resource alternatives and their respective impacts on ratepayer costs. Without such an analysis, the CAISO does not believe there is sufficient information to establish that the preferred resource alternatives are economically infeasible.

C. Any New RFO Should Be Expedited to Meet Local Capacity Needs While Maintaining Compliance State Policies.

To the extent a new RFO is authorized, this Commission should work with the CPUC, the CAISO, SCE and other interested parties to ensure that the new RFO is expedited to meet local reliability needs. Currently, the Ormond Beach and Mandalay 1 and 2 generation facilities are scheduled to retire in compliance with the state's once-through-cooling policy at the end of 2020. To maintain this compliance schedule, new local capacity resources should be in place and operational prior to the summer 2021 peak-load period. As a result, SCE and the CPUC would need to expedite any new RFO for preferred resources in the Moorpark sub-area.

With just over three years before the once-through-cooling compliance deadline, there appears to be an opportunity to conduct an expedited RFO and operationalize preferred resources prior to the summer 2021 timeframe. The CAISO also notes that the 130 MW

Mandalay 3 unit is not subject to the once-through-cooling policy and can reduce the local capacity requirement deficiency in the Moorpark sub-area by 130 MW if it remains in service. In such a circumstance, the Mandalay 3 unit could serve as a component of a short-term bridge to meeting local capacity requirements until there are sufficient preferred resources to meet reliability needs.

D. Conclusion

The CAISO appreciates the opportunity to file these comments and looks forward to collaborating with the Commission and all interested parties to maintain long-term electric reliability in the Moorpark sub-area.

Respectfully submitted,

/s/ Jordan Pinjuv

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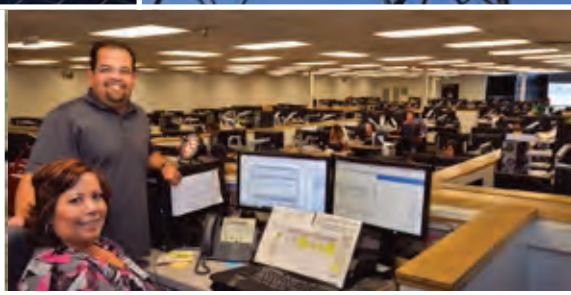
FOOTNOTE 33

Los Angeles LADWP Department of Water & Power

2016 Briefing Book



Putting Customers First

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Introduction

The Los Angeles Department of Water and Power (LADWP) is the nation's largest municipal utility, having provided water and power service to Los Angeles residents and businesses for over 100 years. More than 9,400 employees serve the City of Los Angeles with water and power in a cost-effective and environmentally responsible manner. LADWP is guided by a five-member Board of Water and Power Commissioners, appointed by the Mayor and confirmed by the City Council. LADWP is a proprietary agency of the City, with full responsibility for meeting the electric and water requirements of 4 million people in Los Angeles.

LADWP continues a major transition of its water and power supplies while working to maintain and improve reliability. Working together with the Mayor and City Council, LADWP is creating a clean energy future for Los Angeles and planning for a sustainable water future — one that addresses drought conditions by reducing reliance on expensive imported purchased water and increasing the local water supply as well as conservation.

In 2015, LADWP took the necessary steps to put forth a five-year water and power rate request, which was presented to the public over six months starting in July 2015. Led by General Manager Marcie Edwards, the Department engaged our customers, elected officials, neighborhood councils, the business community, environmental leaders and other stakeholders in a widespread education and outreach effort that encompassed more than 80 presentations and briefings throughout the city. The new rates, which were approved by the City Council in March 2016, went into effect April 15, 2016.

Key priorities for the rates request included:

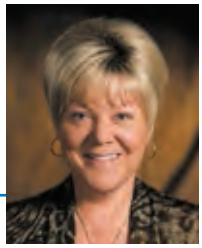
- Replacing aging water and power infrastructure to ensure future service reliability
- Transforming water and power supplies to protect the water supply from drought and transform the power supply to meet clean energy mandates
- Continue improving customer service and keeping rates competitive

Based on input from the independent Office of Public Accountability/ Ratepayer Advocate and stakeholders, the water and power rate ordinances incorporate interim rate reviews and metrics reporting requirements to improve LADWP's performance, accountability and transparency.

This annual Briefing Book is designed to help frame the key initiatives and issues that drive the Department's operations, programs and policies.

LADWP Leadership

Marcie L. Edwards
General Manager



Marcie L. Edwards, General Manager

Marcie L. Edwards was confirmed by the City Council on February 21, 2014 to serve as LADWP General Manager, becoming the first woman to hold the LADWP's top job.

Coming home to the utility where she previously worked for 24 years, Ms. Edwards brings decades of experience in the utility industry to the post. Among her top priorities are improving customer service, resolving billing issues related to the conversion of LADWP's customer information system, overseeing LADWP's transition to a clean energy future through further development of renewable energy and local solar expansion, increased energy efficiency, water conservation, and developing more local water resources to combat climate change and drought. She is also strongly committed to increased transparency and outreach to LADWP's "customer-owners."

She came to work for the Department in 1976 as a 19-year-old clerk typist. She gained experience in a variety of Power System positions, including steam plant assistant, a plant equipment operator, a steam plant operator, a load dispatcher, and a senior load dispatcher. She worked her way up to become superintendent of load dispatching, energy control center manager, manager of bulk power operations/maintenance, bulk power business unit director, and assistant general manager for the marketing and the customer service business units.

Prior to returning to LADWP, Ms. Edwards ran Anaheim's Public Utilities for 13 years, and was tapped to serve as Anaheim City Manager in July 2013.

A past Governor on the California Independent System Operator Board, Ms. Edwards also served as interim CEO of that agency in 2004, and, in that role, assisted in avoiding statewide power outages during the energy crisis.

Board of Water and Power Commissioners

Board President Mel Levine was appointed to the Board of Water and Power Commissioners by Mayor Eric Garcetti and was confirmed by the Los Angeles City Council on September 11, 2013. He was elected President of the Board on October 1, 2013. Mr. Levine joined the international law firm of Gibson, Dunn & Crutcher as a partner in 1993. He retired as a partner in the firm in 2012 but continues to act as Counsel. He served as a member of the United States Congress from 1983 until 1993 and as a member of the California Assembly from 1977 to 1982.

William W. Funderburk Jr., Vice President, was appointed to the Board of Water and Power Commissioners by Mayor Eric Garcetti and was confirmed by the Los Angeles City Council on September 11, 2013. He was elected as Vice President on October 1, 2013. Mr. Funderburk is a founding partner of Castellón & Funderburk LLP, a business litigation boutique.

Jill Banks Barad was appointed to the Board of Water and Power Commissioners by Mayor Eric Garcetti and was confirmed by the Los Angeles City Council on September 11, 2013. She is a recognized civic leader and businesswoman.

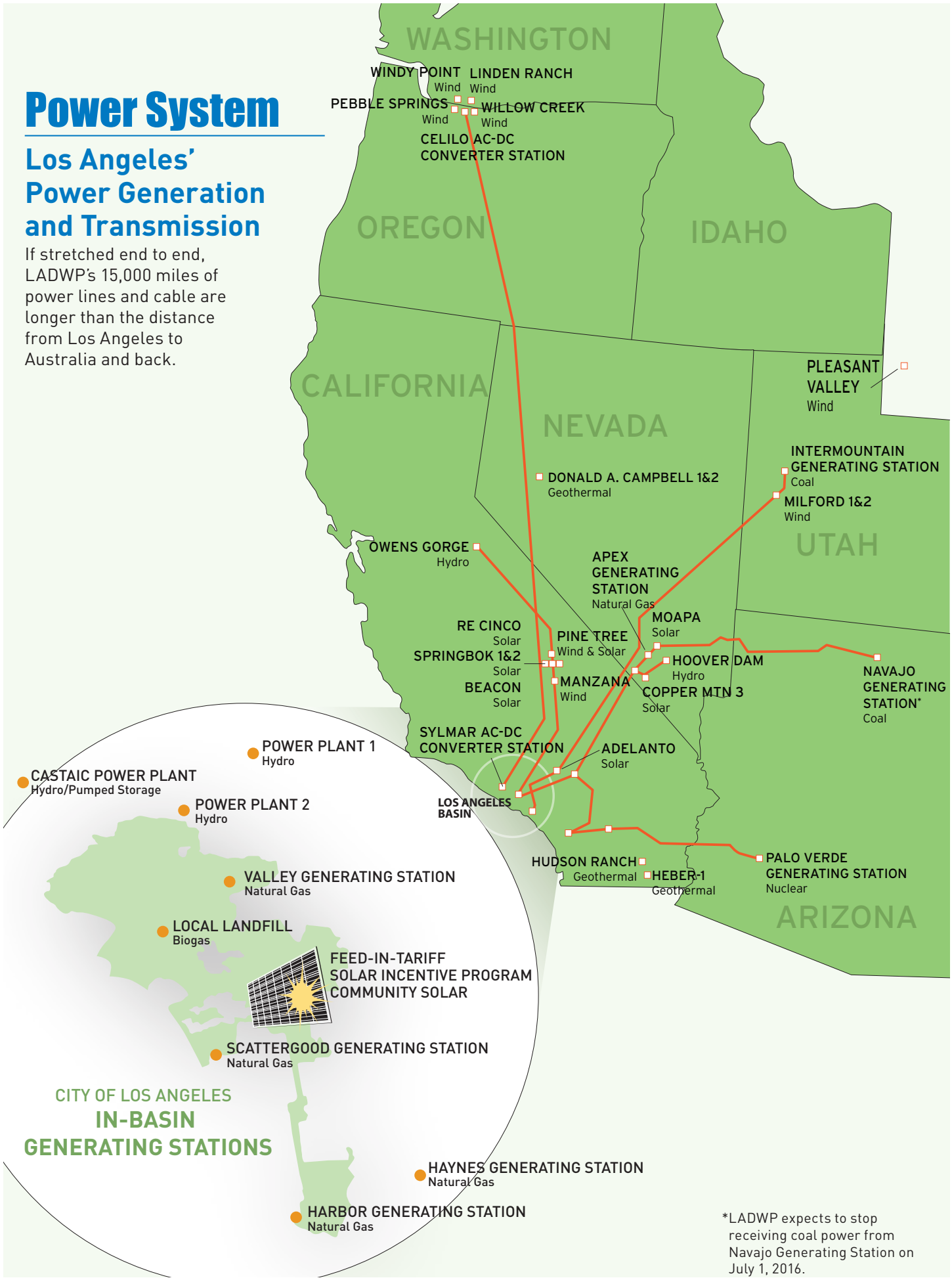
Michael F. Fleming was appointed to the Board of Water and Power Commissioners by Mayor Eric Garcetti and was confirmed by the Los Angeles City Council on September 11, 2013. Mr. Fleming is the Executive Director of the David Bohnett Foundation.

Christina Noonan was appointed to the Board of Water and Power Commissioners by Mayor Antonio R. Villaraigosa and confirmed by the Los Angeles City Council on August 10, 2010. She was re-appointed by the Mayor and then re-confirmed by City Council on August 12, 2011. She is a Senior Vice President of Jones Lang LaSalle's Los Angeles office.

Power System

Los Angeles' Power Generation and Transmission

If stretched end to end, LADWP's 15,000 miles of power lines and cable are longer than the distance from Los Angeles to Australia and back.



*LADWP expects to stop receiving coal power from Navajo Generating Station on July 1, 2016.

Power System

Andrew C. Kendall
Executive Director - Construction, Maintenance & Operations

Michael S. Webster
Executive Director - Engineering & Technical Services

LADWP's Power System is the nation's largest municipal electric utility, and serves a 465-square-mile area in Los Angeles and much of the Owens Valley. LADWP began delivering electricity in Los Angeles in 1916.

Power Facts and Figures

LADWP's Power System supplies more than 26 million megawatt-hours (MWh) of electricity a year for the City of Los Angeles' 1.4 million residential and business customers as well as over 5,000 customers in the Owens Valley.

Revenues & Expenditures

For fiscal year 2015-16, the Power System budget is $4.1 billion. This includes $1 billion for operations and maintenance, $1.6 billion for capital projects, and $1.5 billion for fuel and purchased power.

City Transfer

The Power System transfers 8 percent of its gross operating revenue (estimated at $265.6 million in (FY 2014-15) to the City's General Fund each year to provide critical City services such as public safety.

Electric Capacity

LADWP has over 7,640 megawatts (MW) of generation capacity from a diverse mix of energy sources.

Power Resources (2014)

(As reported to CEC)

Renewable energy	20%
Biomass & Biowaste	5%
Geothermal	1%
Small hydroelectric	1%
Solar	1%
Wind	12%
Natural gas	22%
Nuclear	9%
Large hydro	2%
Coal	40%
Other/Unspecified	7%

Power Use

Typical residential energy use per customer is about 500 kilowatt-hours (kWh) per month. Business and industry consume about 70 percent of the electricity in Los Angeles, but residents constitute the largest number of customers. The record instantaneous peak demand is 6,396 MW reached on September 16, 2014.

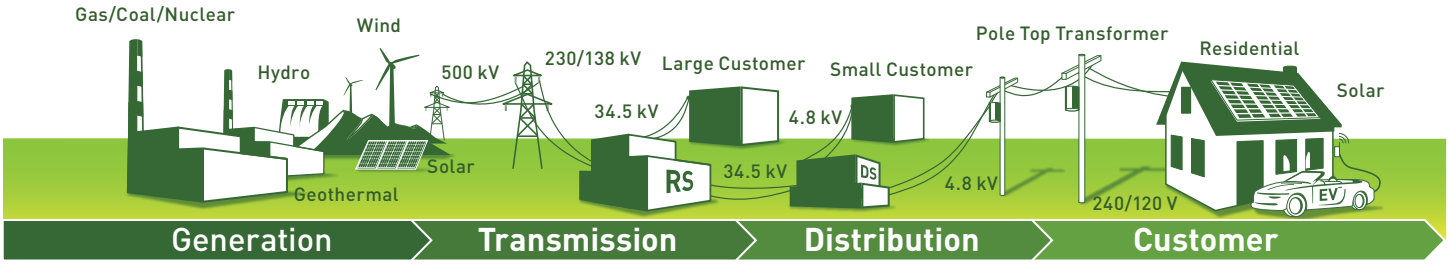
Power Infrastructure

The Power System is responsible for inspecting, maintaining/replacing, and operating the following:

Generation
4 in-basin thermal plants
14 small hydroelectric plants
1 large hydroelectric plant
1 wind plant
2 solar photovoltaic plants

Transmission
3,507 miles of overhead transmission circuits (AC and DC) spanning five Western states
124 miles of underground transmission circuits
15,452 transmission towers

Distribution
6,752 miles of overhead distribution lines
3,626 miles of underground distribution cables
160 substations
50,636 substructures
308,523 distribution utility poles
3,166 pole-mounted capacity banks
1.28 million distribution crossarms
31,728 utilitarian streetlights
128,693 distribution transformers



Power Supply Transformation

Over the next 15 years, LADWP will replace more than 70 percent of its existing power supply as well as rebuild and modernize much of its aging power grid infrastructure used to reliably deliver power to its customers.

LA's clean energy future—a future with more efficient use of energy, greater reliance on renewable energy, and zero coal—is being built right now through a complete transformation of LADWP's power supply.

To transition to a clean energy future, LADWP is making unprecedented investments in:

- Coal Transition
- Energy Efficiency
- Renewable Energy
- Rebuilding Local Power Plants
- Power Reliability
- Electric Transportation

All of these elements are essential to replacing coal power and creating a clean energy future for LA.

Integrated Resource Plan

The Power Supply Transformation is guided by LADWP's Integrated Resource Plan (IRP), a roadmap for transitioning out of coal while maintaining a reliable power supply, and doing so in a cost-effective manner. The IRP has been developed through a collaborative process and is updated every two years with input from customers and stakeholders.

The IRP balances key objectives of:

- Maintaining a high level of service reliability
- Maintaining competitive rates
- Exercising environmental stewardship, including a reduced carbon footprint

➔ Go to **www.ladwp.com/powerIRP** to learn more.

Coal Transition

Legislative Requirement

The California Greenhouse Gas Emissions Performance Standard (SB 1368) sets a cap on the level of greenhouse gas emissions from power imported into the state. LADWP is required to stop receiving coal power from two coal-fired generating stations when their current contracts and agreements expire.

Coal Transition Strategy

The Power System Integrated Resource Plan calls for replacing the portion of coal that LADWP receives each year from Navajo Generating Station in Arizona and Intermountain Power Plant (IPP) in Utah by increasing energy efficiency to at least 15 percent by 2020, expanding renewable energy to 33 percent by 2020 and 50 percent by 2030 while integrating and balancing this power with efficient and cleaner burning combined-cycle natural gas as a "bridge fuel" to ensure reliability.

Recent Accomplishment

Coal Transition Progress

In March 2013, the LADWP Board approved a contract that will enable LADWP to completely transition out of coal power. In collaboration with participating power utilities, LADWP will convert IPP to a smaller natural gas-fired generating station by 2025 at the latest, with efforts to begin that transition by 2020. Reducing the size of IPP will also free up transmission capacity to bring more renewable energy into Los Angeles.

In 2015, LADWP sold its 477 MW share of coal power from Navajo Generating Station to Salt River Project and the sale will close on July 1, 2016. The Navajo and IPP actions are major steps toward the transformation of the LADWP's power supply to create a cleaner and more sustainable energy future for Los Angeles.

Through these actions, the City of Los Angeles became the first major city in the United States to commit to becoming coal free.

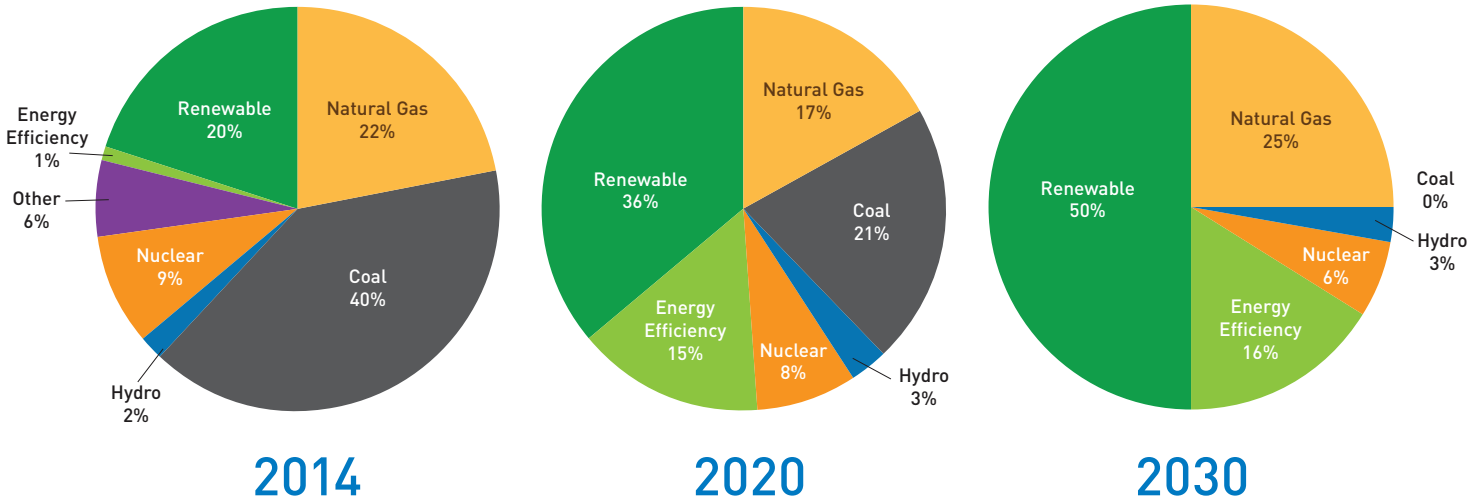
Reliability Through Integration

Completely eliminating coal from LA's power supply is a monumental step for LADWP. It is vital that policymakers, customers and stakeholders understand that this transition poses many challenges, and requires careful resource planning to maintain a steady flow of power to LA.

Coal power provides a reliable and steady flow of continuous baseload power, 24/7, while renewables such as wind and solar vary every day, throughout the day. Most renewables alone cannot replace coal as "baseload" power. For this reason, using clean and efficient combined-cycle natural gas is an important part of the coal replacement strategy. Cleaner burning natural gas provides a critical bridge fuel to ensure reliability.

All elements of LADWP's power supply transformation—energy efficiency, increased renewable energy, rebuilding its coastal power plants and securing new, cleaner burning natural gas—are needed to maintain reliability and ensure a successful and cost-effective transition out of coal.

LA's Future Power Supply Is Coal-Free



*Estimated percentages will differ from CEC reporting requirements (e.g. accounting for energy efficiency as a resource).

Road To Renewables

Legislative Requirement

State law (SB2 (1X) and SB350), as recently interpreted by the California Energy Commission (CEC), requires that California utilities meet the following Renewable Portfolio Standard (RPS) levels:

- Maintain average of 20% between 2011 and 2013
- 25% by 2016
- 27% by 2017
- 29% by 2018
- 31% by 2019
- 33% by 2020
- 40% by 2024
- 45% by 2027
- 50% by 2030 and thereafter

Recent Accomplishment

LADWP achieved 20 percent renewable energy delivered to customers in 2010, and is on track to meet 25 percent by 2016 and 33 percent by 2020.

A major focus of the 2015 and 2016 IRPs is to evaluate strategies to achieve the new goals established by recent state legislation (SB350) for 50 percent renewables by 2030.

RPS Expansion Policy

As LADWP expands its renewable resource portfolio, it is important that it do so in a cost-effective manner to minimize the impact on ratepayers. Some of the key considerations in selecting these resources include:

- Costs and operational impact of integrating renewables
- Technologies that deliver more energy during peak hours
- Preference for local projects
- Locating projects near existing transmission and other LADWP assets such as land and power infrastructure
- Diversification of resources

Recent Renewable Energy Projects

The following are renewable energy projects approved, under construction, and/or completed in the past two years that contribute to meeting LADWP's RPS goals:

Barren Ridge Renewable Transmission Project

Construction continued on a critical power transmission line that will enable LADWP to deliver additional renewable energy resources from the Tehachapi Mountains and Mojave Desert areas to Los Angeles. Crossing Kern and Los Angeles Counties, the Barren Ridge line will provide up to 2,000 MW of additional power transmission capacity to access vital wind and solar resources that are necessary to meet the RPS goals. The new line is scheduled to be in service by late summer 2016.

Recent Accomplishment

Barren Ridge and Haskell Switching Stations

After 2 ½ years of construction, Barren Ridge Switching Station Expansion was placed in-service in summer 2015. This critical station will connect the new Barren Ridge transmission line as well as several major solar projects (Beacon Solar – 250 MW, Springbok Solar 1 and 2 – 250 MW, and RE Cinco Solar – 60 MW) that are currently under construction or planned. Haskell Switching Station, the southern hub for the Mojave renewable corridor, is expected to be placed in service by April 2016.

Donald A. Campbell Geothermal Plant

Beacon Solar Project

In 2014, LADWP broke ground on the Beacon Solar Project, which will provide 250 MW of solar power. The project, which was already permitted for building ground-mounted solar photovoltaic systems, is situated adjacent to LADWP's Barren Ridge Switching Station in Kern County as well as the Pine Tree Wind and Solar projects. It will make use of the additional transmission capacity that will be available, making the area a renewable energy hub. The project, which is on schedule for completion by the end of 2016, is an excellent opportunity for large-scale solar and will create hundreds of green jobs in California.

Copper Mountain 3 Solar Project

In April 2015, the City of Los Angeles began receiving 210 MW of solar power from Copper Mountain 3, one of the largest solar arrays in the U.S. LADWP receives the majority of solar energy generated by Copper Mountain 3 in Boulder City, Nevada through the Southern California Public Power Authority (SCPPA), which has a long-term power sales agreement with the plant's owner, Sempra U.S. Gas and Power, to sell the power to LADWP.

Recent Accomplishment

Don A. Campbell Geothermal Power Plants I and 2

The Don A. Campbell 2 Geothermal Power Plant in Mineral County, Nevada was placed in service in September 2015, delivering 16.2 MW of important geothermal energy to Los Angeles homes and businesses. Completed 15 months ahead of schedule, the new plant is an expansion of the first Don A. Campbell plant, which has been delivering geothermal energy to Los Angeles since January 2014. Combined, the first and second phases of the plant are providing close to 30 MW of renewables for Los Angeles with an energy output of 245,000 megawatt-hours (MWh) annually—enough to serve 41,500 households and avoid 139,100 metric tons of carbon emissions, which is equivalent to removing 26,900 cars off the road.

Recent Accomplishment

Heber-1 Geothermal Project

Through another power purchase agreement, LADWP began receiving 34 MW of baseload, around-the-clock renewable geothermal energy from the existing Heber-1 Geothermal Project in Imperial County. LADWP started receiving power from the plant on an interim contract in December 2015. The 10-year contract began in February 2016.

Recent Accomplishment

Hudson Ranch 1 Geothermal Project

In 2015, LADWP entered into an agreement to purchase approximately 55 MW of renewable geothermal energy from Salt River Project's rights in the Hudson Ranch Geothermal Project located in the Imperial Valley of Southern California through 2021.

Manzana Wind Project

The Manzana Wind Project provides 39 MW of renewable energy to LADWP over a 10-year term effective December 2012. The power is generated by an existing 189 MW wind farm in Kern County. This project also provides a unique opportunity for LADWP to gain additional experience in working with the California Independent System Operator (CAISO), since the power is delivered to a Southern California Edison substation and then scheduled into the CAISO-controlled transmission system. Utilizing CAISO opens up more potential renewable projects and continues the spirit of cooperation as all California utilities find ways to meet the state's renewable energy requirements.

Recent Accomplishment

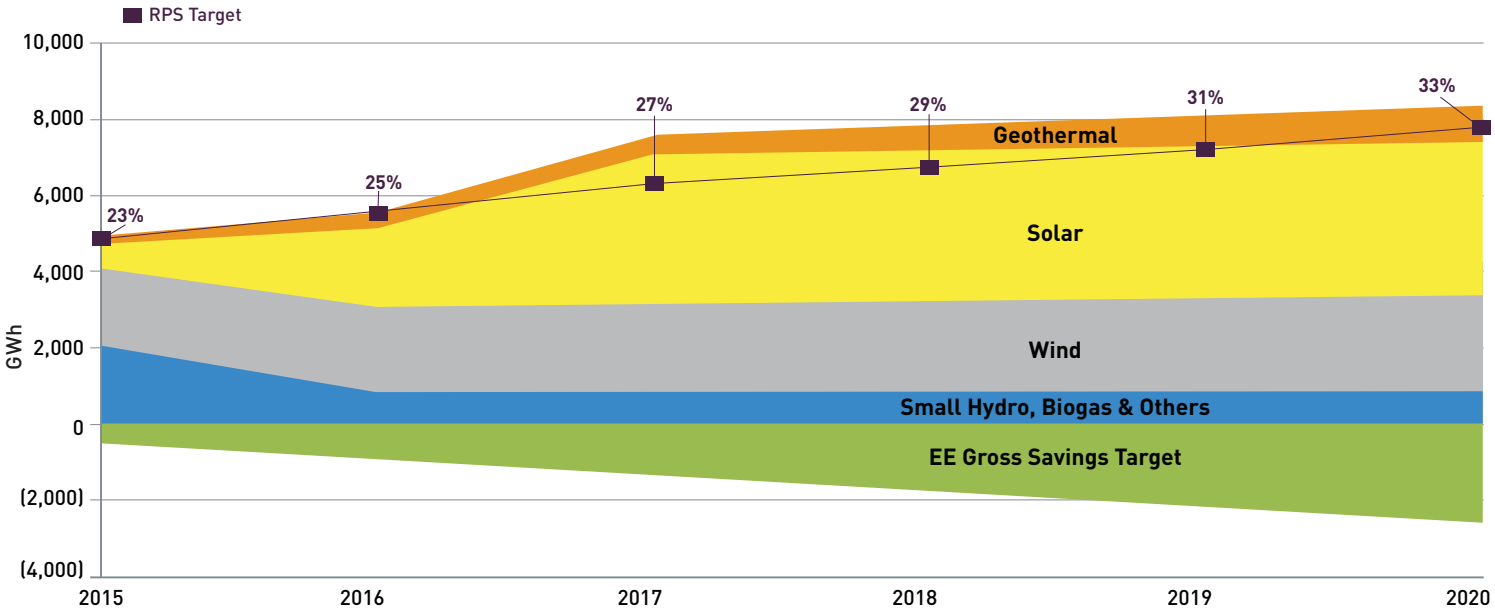
Moapa Solar Project

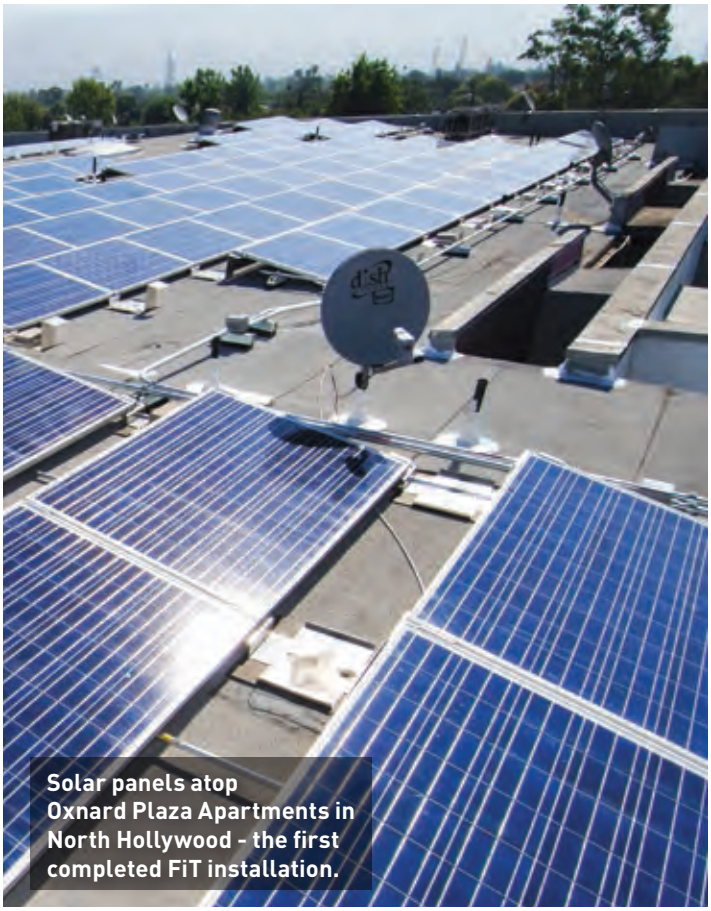
LADWP has entered a contract with the Moapa Southern Paiute Solar Project to deliver clean, solar energy for 25 years from a new utility-scale solar plant, which is under construction and expected to be complete in June 2016. LADWP will receive up to 250 MW of solar power from the new facility, located on approximately 2,000 acres on the Moapa River Indian Reservation in Clark County, Nevada.

Springbok Solar Power Projects 1 and 2

Power purchase agreements for Springbok 1 and 2 were approved by the Board in 2014 and 2015, respectively. Springbok 1 and 2 will generate 100 MW and 150 MW, and are expected to be in operation by the end of 2016.

Increasing Renewable Energy and Energy Efficiency





Solar panels atop Oxnard Plaza Apartments in North Hollywood - the first completed FiT installation.

Local Solar Programs

A key element of LADWP's renewable energy program is the development of local solar, particularly customer-based programs that tap into the city's abundant sunshine. Local solar projects help to meet LADWP's renewable energy targets and reduce the carbon footprint created by fossil fuel-burning power plants. Solar is also expected to be a vital catalyst for creating jobs and stimulating the green economy in Los Angeles.

Local solar projects are also beneficial to Los Angeles because they are "distributed generation," functioning like mini power plants that generate energy right where it is being used.

LADWP offers two local solar programs: the Solar Incentive Program and the Feed-in Tariff (FiT) Program. LADWP expects to launch a pilot Community Solar Program in 2016.

Solar Incentive Program

Legislative Requirement
In September 2007, LADWP revised its earlier Solar Incentive Program (SIP) guidelines to comply with SB1, the California Solar Initiative. Under this requirement LADWP committed to provide $313 million to support solar photovoltaic (PV) projects through 2016, with a goal of achieving 280 MW of solar PV by the end of that period.

Early in the program, LADWP's customer incentives were set higher than the State-mandated minimums in order to encourage greater participation in solar given LADWP's lower electric rates as compared to other California utilities.

As participation grew dramatically in response to increased availability of tax credits and dropping solar prices, the Board of Water and Power Commissioners lowered future incentive levels to be more in line with the State-mandated minimum levels. LADWP anticipates that by the end of the SB1 program in 2016, the Department will be very close to achieving its goal of 280 MW of customer solar generation.

Record Levels
In September 2011, LADWP relaunched SIP with a new incentive structure designed to increase customer participation while keeping the program at a manageable pace. Since then, LADWP has seen record levels of program participation. In 2015, customers submitted an average of 600 applications per month, compared to 40 per month in 2007 and 2008.

Recent Accomplishment

Solar Achievement
As of December 31, 2015, LADWP has paid approximately $272 million to customers in solar incentives. This amount includes $55 million provided prior to implementing the SB1 required program, and $217 million under SB1.

There are over 19,500 customer-installed solar systems connected to the grid. This represents 152 MW of solar capacity and generates 250,000 MWh per year.

Recent Accomplishment

Program Improvements
Responding to requests to speed up solar interconnections, LADWP revamped the SIP process to enable customers to get their new solar PV system up and running faster by separating the meter installation and interconnection process from the rebate process, among other changes. Effective December 4, 2015, customers, contractors and installers no longer have to wait for rebate applications to be processed in order to turn on a new solar system. Customers and installers may apply directly for the net meter installation and interconnection through a new website, www.ladwp.com/nem.

Among other changes designed to reduce delays, LADWP has modified its online reservation system so users can receive instantaneous reservations of incentive funds. In addition, the electrical requirements for systems under 10 kilowatts have been simplified to expedite meter installations and reduce installation costs.

➔ Go to **www.ladwp.com/solar** to learn more.

Feed-in Tariff Solar Program

Legislative Requirement

State legislation SB1332 requires utilities to provide a Feed-in Tariff (FiT) program that enables third parties to develop solar, or other renewable energy, and sell the power to the utility. LADWP's share of the statewide program is 75 MW.

Program Launched

LADWP has initiated the nation's largest municipal solar FiT program for up to 150 MW, which is more than the State's requirement, to expand solar energy in Los Angeles and boost the local economy. The program, which evolved through external meetings and discussions with over 500 stakeholders, was launched as a 10 MW demonstration program. After the pilot, LADWP launched the full 150 MW FiT program, including a 100 MW set-pricing program and a 50 MW program that bundles small local solar installations with a large-scale solar project on LADWP-owned land in the Mojave Desert.

FiT Demonstration Program

Designed to test the pricing structure and refine other program elements, the Demonstration Program garnered 26 applications for 7.2 MW of solar power. Out of these applications, three projects for 1.6 MW have been installed and will generate 3,100 MWh per year.

Recent Accomplishment

FiT100 Program

Since approving the 100 MW FiT Set Pricing Program in 2013, LADWP has offered five allocations totaling 100 MW for solar and other eligible renewable energy. Through the FiT Program, LADWP purchases power from third parties at a fixed price per kWh (based on a declining scale) under a standard offer power purchase agreement.

Since the program began, 23 FiT solar projects have been placed in service with an energy capacity of 14 MW. An additional 12.4 MW of solar FiT projects have approved contracts and are pending construction. As of February 2016, a total of 327 MW of solar projects have been reviewed and 64.6 MW of those projects are being considered for final approval.

FiT50/Beacon Bundled Solar Project

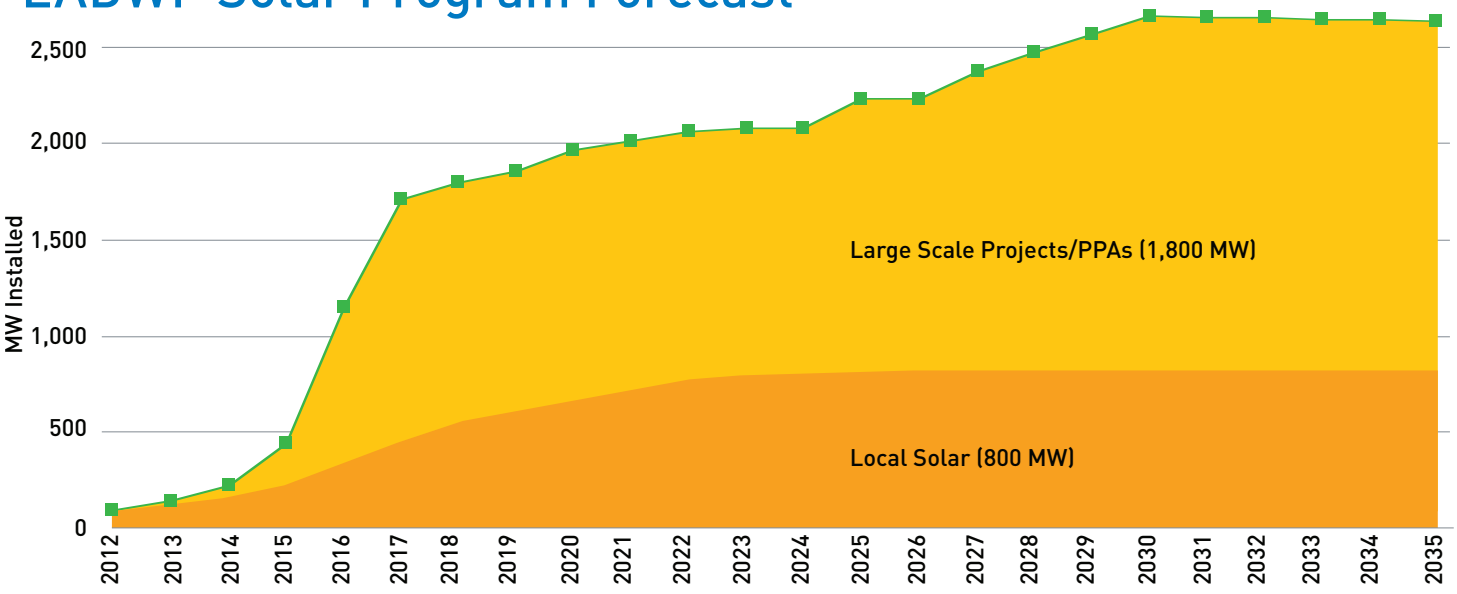
Approved in April 2013, this innovative program bundles 50 MW of local FiT solar projects as a requirement for bidding on the large-scale Beacon Solar Project, which has a total capacity of 200 MW available. This is a competitive pricing program aimed at developers interested in building large scale solar, and leveraging their resources to also expand rooftop solar projects within Los Angeles. The FiT 50 projects are in development and expected to be complete in February 2017.

Expanded FiT Program

In fall 2014, LADWP began developing an Expanded FiT Program. Paced at 50 MW per year, the Expanded FiT Program will be priced in a manner that is responsive to program participation. If approved by the Board of Water and Power Cummissioners and City Council, LADWP would launch the Expanded FiT Program by mid-2016.

➔ Go **to www.ladwp.com/FIT** to learn more.

LADWP Solar Program Forecast



*Local Solar combines energy from the SIP, FIT

Rebuilding Local Power Plants

Regulatory Issue

Once-Through Cooling (OTC) is the process of drawing ocean water and pumping it through a generating station's cooling system, then discharging it back into the ocean. The impact of OTC on ocean habitat is governed by the Federal Clean Water Act Section 316(b), administered by the State Water Resources Control Board, which developed a statewide policy in 2010 to reduce or minimize the impact of OTC on marine life.

Therefore, LADWP is eliminating the use of ocean water for cooling at its three coastal power plants—Scattergood, Haynes and Harbor Generating Stations—by 2029. This requires major capital projects, costing about $2.2 billion, employing complex engineering and design, and building in tight quarters without disrupting neighbors.

The repowering projects are especially challenging because they require concise timing in their planning and execution. No generating unit can be removed from service before its replacement is online.

Repowering Strategy

LADWP is pursuing a strategy to comply with state policy while also reconfiguring and modernizing its oldest generating units to increase reliability and to integrate renewable energy.

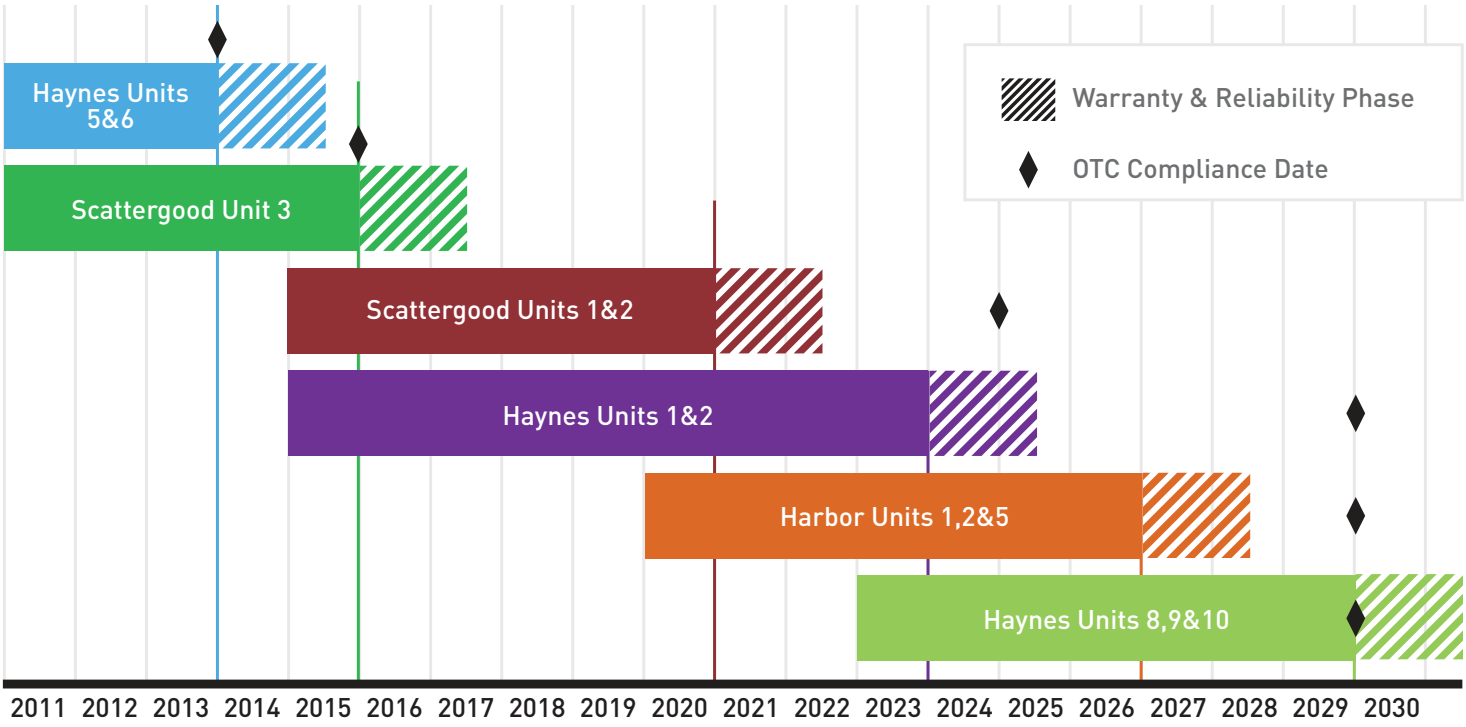
As LADWP works to expand renewable energy and eliminate coal power to achieve a clean energy future for Los Angeles, natural gas provides important "bridge fuel" to ensure efficient but reliable power supply. This is necessary because the most abundant renewable resources, solar and wind, are both variable. They do not produce energy if the wind is not blowing or the sun is not shining. Until more energy storage technology can be developed, natural gas is necessary to firm and back up renewables to ensure continuous, reliable power to LADWP customers 24/7.

Recent Accomplishment

Scattergood Generating Station

In December 2015, LADWP completed the first phase of modernizing Scattergood Generating Station in Playa Del Rey, replacing a 1970s-era conventional steam turbine with advanced power generation technology that will increase fuel efficiency and reduce emissions by 33 percent, while improving reliability and flexibility to ramp up to full power at a faster pace to meet peak demand periods. The Scattergood repowering will also reduce harmful impacts on marine life by replacing ocean cooling with an advanced air-cooling system. Scattergood Unit 3 has been replaced with 533 MW of a highly efficient gas-fired generation system consisting of a combined cycle system (natural gas and steam) and two quick-start turbines that can ramp up within 10 minutes from cold iron to full power. As a result of the rebuilding efforts, the flow of ocean water through Scattergood generating units has declined by over 54 percent, from approximately 495 million gallons per day (MGD) in 1990 to 224 MGD as of December 31, 2015.

Timeline for Rebuilding Local Power Plants



LADWP's schedule for OTC compliance.

With Phase 1 of the Scattergood Repowering Project complete, LADWP will focus its efforts on Phase 2, replacing and repowering Scattergood Units 1 and 2 with a combined-cycle generating unit that will utilize air-cooling in lieu of ocean water cooling. The old Scattergood Unit 3 will be demolished to create the construction area for the new generating unit, which is expected to be constructed by December 2020.

▼ **Scattergood Generating Station repowered with highly efficient generating system**

Haynes Generating Station

LADWP completed the first project to eliminate ocean cooling at Haynes Generating Station in June 2013. LADWP replaced two aging generating units with six 100 MW quick-start turbines that use air, rather than ocean water, for cooling. As with the new turbines at Scattergood, the faster units improve operational flexibility, using rapid start technology to ramp up to full power within 10 minutes.

Investing in Energy Efficiency

Legislative Requirement

Under AB 2021, publicly-owned utilities such as LADWP must identify, develop and implement programs for all potentially achievable, cost-effective energy efficiency savings and establish annual targets.

Transformation Element

Recognizing energy efficiency is a key element in the power supply transformation and aligning with the State legislation, LADWP has increased its goal to 15 percent cumulative energy savings by 2020, based on the most recent potential study completed in 2014. The new cumulative energy savings target, covering a 10-year period through 2020, is equivalent to powering about 61,500 homes annually.

Increased Investment

To achieve the 15 percent energy reduction by 2020, LADWP has significantly increased investment in energy efficiency over the past four years.

Guiding Principles

Since August 2012, LADWP has applied the following guiding principles for launching new and redesigned energy efficiency programs:

- Promoting energy efficiency programs for all customer sectors
- Targeting "hard-to-reach" customers (i.e. low-income residents, small businesses)
- Achieving tangible economic benefits for low-income customers
- Leveraging programs to support jobs for local workforce
- Working collaboratively with partner agencies on outreach and education, and to reach a broad and diverse customer base through a Southern California Gas Co. (SoCalGas) partnership
- Operating transparently and reporting results regularly

Efficiency Solutions

LADWP's Efficiency Solutions Business Group continues to develop cutting-edge, beneficial programs that cover the gamut of residential and commercial consumer rebates, direct installations for hard-to-reach customers, technical assistance, and incentives for commercial lighting and refrigeration efficiency measures.

Southern California Gas MOU

LADWP and SoCalGas have formed a unique public-private partnership that has expanded the reach of efficiency programs for both LADWP and SoCalGas customers. To date, 16 joint programs have been launched and several others are under development, or being considered.

➔ Go to **www.ladwp.com/energyefficiency** for more detailed information about LADWP Efficiency Solutions programs.

Greenhouse Gas Reductions

Legislative Requirements

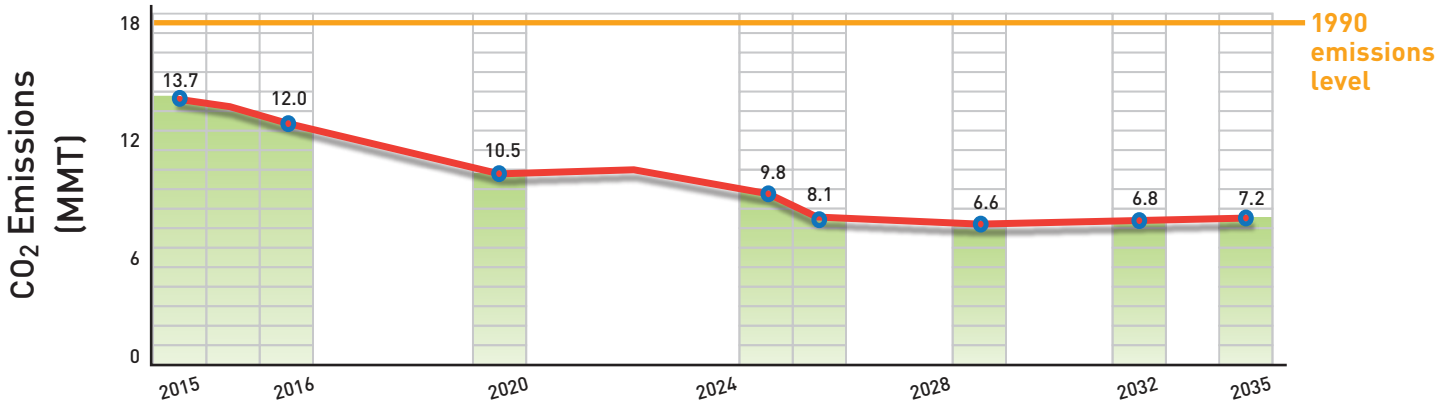
As previously mentioned, SB 1368 establishes a greenhouse gas emission performance standard at the level of, or below, the emission rate of gas-fired combined cycle units. Another piece of legislation, AB 32, the California Global Warming Solutions Act of 2006, calls for reducing the state's CO_2 emissions to 1990 levels by 2020.

Under the final regulations for the greenhouse gas emissions cap and trade program, LADWP receives allowances based on projected greenhouse gas emission reductions. This allows revenues generated through customer rates to be invested into renewable energy and energy efficiency projects that meet the RPS and energy efficiency goals.

On August 3, 2015, the U.S. Environmental Protection Agency finalized the Clean Power Plan, which will reduce

The Result: Creating a Clean Energy Future for LA

LADWP's CO_2 emissions are 23% below LADWP's 1990 level, and expected to be 55% below the 1990 level in 2025.
1990 Emission Level: 17.9 MMT



In 2025, LADWP will have reduced CO_2 emissions by 9.8 million metric tons, compared to the 1990 baseline level, equivalent to removing 2.1 million cars from the highway.

carbon pollution from electric generating units by 32 percent below 2005 levels by 2030. The Clean Power Plan establishes emission goals and guidelines for the electric generating units and requires states to develop plans to implement the guidelines.

Progress in GHG Emissions Reduction

LADWP has reduced its greenhouse gas emissions to 23 percent below its 1990 level due to the shutdown of the Mohave Coal Power Plant in 2005, ongoing repowering programs that began in the 1990s, and increased development of renewable resources.

LADWP's greenhouse gas emissions will decline dramatically as it progresses with plans to eliminate coal power, increase renewable energy and energy efficiency, and rebuild local power plants to be more efficient. Greenhouse gas emissions are expected to be 55 percent below the 1990 level by 2025—the equivalent of removing 2.1 million cars from the highway.

Power Reliability

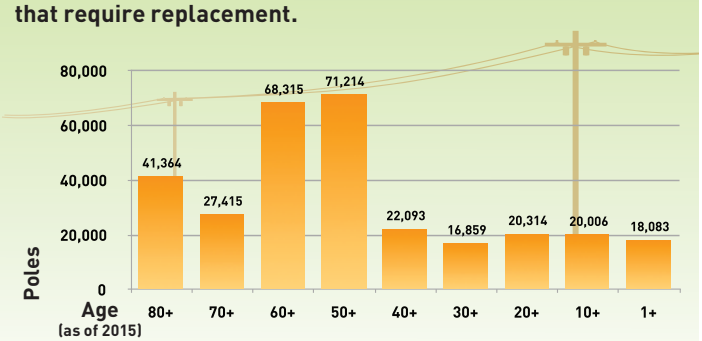
A significant ongoing issue for LADWP's Power System is the need to upgrade or replace critical aging power infrastructure to ensure continued reliability for its customers.

While a significant amount of work has been accomplished on LA's generating facilities, the power distribution infrastructure, such as poles and underground cables, remains a major focus, since this equipment is aging rapidly and requires increased investments going forward.

The majority of LADWP's power poles was installed during the city's rapid growth—1940s through 1960s. For example, if LADWP were to replace 5,000 poles a year, it would take over 25 years to replace all of the poles that are 60-plus years old (the average expected pole lifespan). During that time another 110,000 poles will become 60-plus years old, which would take another 22 years to replace. While not all poles over 60 years of age will need to be replaced, some newer poles may need to be replaced due to other factors.

Another area of concern is the backlog of temporary repairs awaiting permanent repair. There are approximately 53,000 of these "fix-it tickets" in the queue, and the number is growing by about 1,000 jobs per year.

Power poles are among the critically aging infrastructure that require replacement.



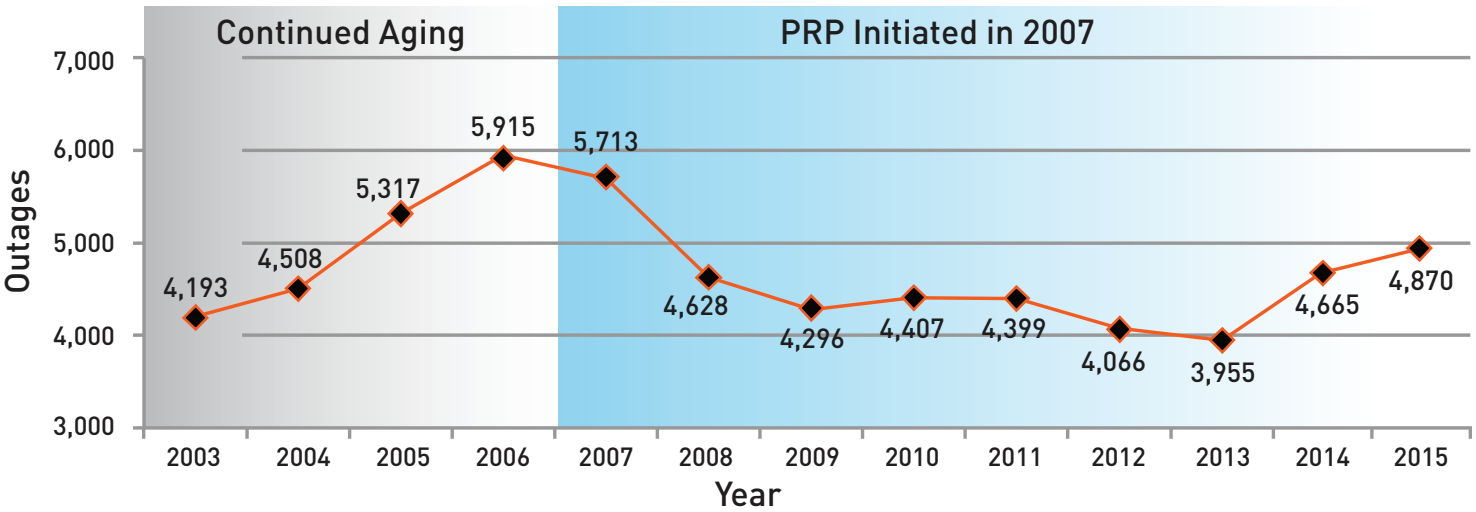
Note: approximately 3,917 poles do not have install dates

Recent Accomplishment

Power System Reliability Program

To address the problem of aging infrastructure, LADWP has: 1) expanded the original Power Reliability Program (PRP) to encompass all major functions of the Power System, including generation, transmission, substation, and distribution; 2) cost effectively prioritized reliability expenditures; 3) accelerated the replacement of aging Power System equipment; and 4) initiated a process to use contractors to assist in replacing its aging poles and cables.

Power Outages Relative to Investment Level



Electric Transportation Program

LADWP is a leader in fostering electric vehicle (EV) technology. The benefits of electrification include reducing the city's carbon emissions, saving costs for drivers because charging up vehicles is less expensive than gas, and helping integrate renewable energy into the LADWP power grid.

Recent Accomplishment

Charge Up LA! Rebate Program

To encourage Angelenos to buy or lease an electric vehicle, LADWP offers the "Charge Up LA!" EV Charger Rebate Program for residential, commercial and public agency customers. From June 2013 through November 2015, the Department paid over $2.8 million in EV charger rebates for 1,970 chargers under the program.

In February 2016, the Board of Water and Power Commissioners renewed the program with a higher rebate for commercial customers—up to $4,000 per installed charger—to foster more widespread charging opportunities at work and other public locations as well as for condominium and apartment complexes. The idea is to build confidence among EV drivers that they can travel farther from home without fear of running out of power. The updated program, which will run through June 2018, continues offering rebates of up to $500 to residential customers for the first home charger and an additional $250 if the customer installs a dedicated electric service for an EV.

Recent Accomplishment

Public Charging Stations

LADWP has worked with customers to install over 300 chargers located on City of Los Angeles property and at private, publicly accessible locations. LADWP has also installed 14 DC fast chargers at publicly accessible locations, and also received grant funds to install 104 more.

In addition, new EV chargers have been installed at LAX, the LA Department of Transportation parking garages, and the LA Zoo. Electrical infrastructure upgrades will help reduce both the frequency and duration of power outages, and to support the increased power demand necessary for EV charging.

Recent Accomplishment

LADWP EV Fleet

LADWP operates one of the largest plug-in fleets in the City with 67 vehicles. Along with passenger vehicles, LADWP has invested in heavy-duty vehicles including plug-in hybrid bucket trucks and digger derrick trucks.

➔ Go to **www.ladwp.com/ev** to learn more.

Advanced Metering Initiative

The Smart Grid Regional Demonstration Program, called Smart Grid LA, is a joint effort of LADWP, the US Department of Energy (DOE), and a consortium of the region's top research institutions, including USC, UCLA, and JPL. The goal is to deploy and test a host of new technologies, such as automated switches, monitors, controllers, and meters that will relay information to each other through a near-real-time communications network. The Demonstration Program, initiated in 2010, will be completed in 2016. It features a web portal allowing participating customers to share efficiency achievements, receive notifications to reduce energy during peak demand periods, and help meet energy use targets.

Since the Demonstration Program is largely complete, LADWP is investigating the feasibility of a full-scale Advanced Metering Infrastructure (AMI) program. Over the next several years, the prospective program will phase in the systemwide deployment of advanced meters and the underlying communication network that comprises the infrastructure. During the first phase, LADWP expects to initiate broader demand-response offerings and other customer programs that will be expanded in subsequent phases.

The AMI aims to empower LADWP's customers with the proper knowledge and tools to manage their usage and costs, providing them superior reliability and value in their electric service, and continuing to provide responsible environmental stewardship. LADWP will focus on these objectives while engaging in a new partnership with our customers. Ultimately, the program will be broadened to include smart grid technologies for water distribution to improve leak detection and help customers better manage their water use.

➔ Go to **www.ladwp.com/smartgrid** to learn more.

Jobs: Utility Pre-Craft Trainee Program

To create a path for young and new workers into utility careers, LADWP, IBEW Local 18 and other local agencies introduced the Utility Pre-Craft Trainee (UPCT) Program. The training program paves the way for career-path jobs while addressing the issue of rising retirements and the need for new skilled employees. An integral part of the green jobs pipeline for Los Angeles, the UPCT program provides pre-apprenticeship training for entry-level workers who are looking for long-term positions in the water and power utility fields.

Among other jobs, UPCT employees are utilized to perform energy efficiency work, solar installations, and rotate through water, power, and support services, to try other types of work. By offering these positions, LADWP is preparing new workers to fill critical vacant jobs throughout the Department.

Electric Rates and Finance

2016-2020 Electric Rate Request

In March 2016, LADWP received approval of its 2016-2020 power rate changes, which will provide electric rate increases over the next five years. For a typical residential customer using 500 kWh per month, the power rates will increase an average of 1.56 percent each year, or about $5.85 per month annually at the end of five years. For all LADWP customers, including residential, commercial, industrial and governmental customers, the power rates will increase an average of 3.86 percent annually over the five years.

The new rates, which became effective April 15, 2016, will provide about $720 million in new revenues to meet mandates and clean energy goals. Among the various mandates are increasing renewable energy sources, expanding energy efficiency programs, modernizing coastal generating units to eliminate ocean water cooling, eliminating coal and reducing greenhouse gas emissions. Additional revenues will also help ramp up the replacement of aging electrical infrastructure to ensure future reliability.

Rate Structure Changes

The approved electric rate ordinance includes several additional changes in the rate structure developed to meet financial and policy goals. These include:

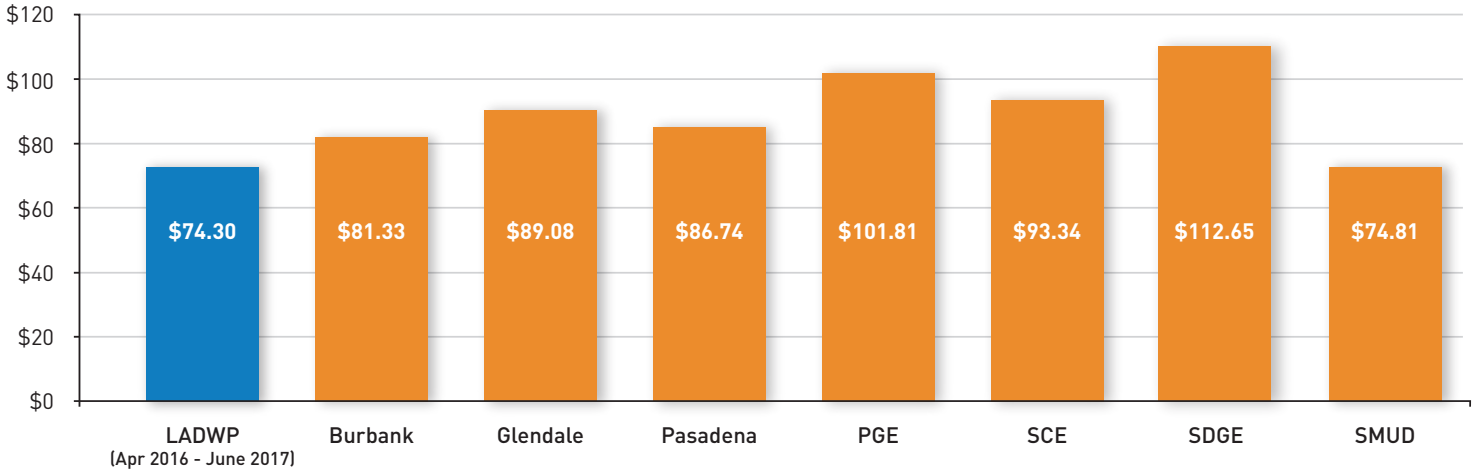
- Adding a power reliability "pass-through" factor to pay for power infrastructure improvements
- Adding a Power Access Charge to cover the fixed costs of operating the power grid based on how much energy a customer consumes
- Rebalancing the rates among customer sectors according to the recent Cost of Service Study
- Adding a Base Rate Revenue Target (BRRT) to encourage conservation while covering LADWP's fixed cost

Comparison of Rates

While rate increases are never easy, LADWP's new rates still remain among the lowest in California. A typical electric customer in LADWP's service area pays approximately 10 to 30 percent less than similar customers served by investor owned utilities in Southern California. LADWP is undertaking the largest capital investment program in its history, while keeping competitive rates by maintaining favorable financial metrics.

➔ Go to **www.myLADWP.com** to learn more.

Comparison of Typical Residential Monthly Bill*



*Based on using 500kWh/month, as of March 2016

Los Angeles Department of Water & Power

Water System

Los Angeles' Water Sources

Water System

Marty Adams
Senior Assistant General Manager - Water System

LADWP's Water System is the nation's second largest municipal water utility, and serves a population of 4 million people within 473 square miles. The Water System supplies approximately 167 billion gallons of water annually and an average of 458 million gallons per day for 681,000 residential and business water service connections.

The availability of water has significantly contributed towards the tremendous growth and development of Los Angeles. Since 1902, when the population in Los Angeles was approximately 146,000, until today, the Water System has worked tirelessly to ensure that Angelenos receive a safe and reliable water supply.

In 2016, now in the fifth year of drought in California, LADWP continues its water conservation efforts. The city has been successful in meeting water conservation mandates established by Mayor Eric Garcetti and the state.

The Water System has identified three areas as its top priorities: **safety** of drinking water, **reliability** of water infrastructure, and **sustainability** of water supplies.

Water Facts and Figures

The Water System is responsible for supplying, treating, and distributing water to the City of Los Angeles.

Revenues & Expenditures

For fiscal year 2015-16, the Water System budget is $1.69 billion, including $462 million for operations and maintenance, $956 million for capital projects, and $272 million for purchased water.

Water Supply Sources (5-year average)*

LA Aqueduct (Eastern Sierra Nevada): 29%
Purchased water (MWD): 57%
Bay Delta 48%
Colorado River 9%
Groundwater:.....12%
Recycled water: 2%
*FY 2011-15

Water Use

Average Daily Use Per Capita: ..... 113 Gallons Per Day (GPD)

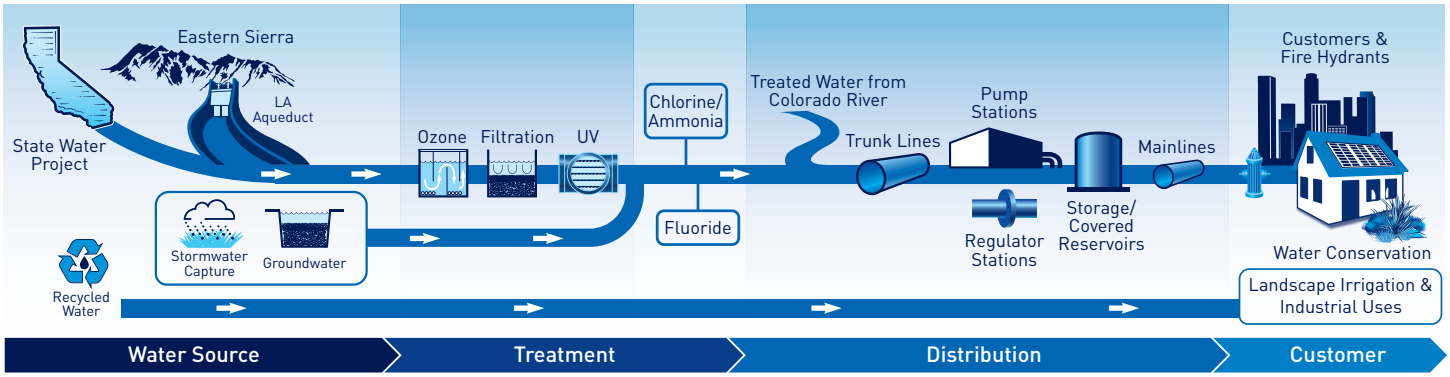
Residential Customers
347,000 acre-feet (428 million cubic-meters) per year, or 310 million GPD

Commercial/Industrial/Institutional Customers
160,000 acre-feet (197 million cubic-meters) per year, or 143 million GPD

Annual Water Sales to Customers
(as of FY 2014-15)
167 billion gallons (or 670 billion liters)
Water Service Connections (Active):.....681,000

Water Infrastructure

Tanks and Reservoirs:..... 119
Pump Stations: 96
Ammoniation Stations:.....9
Chlorination Stations: 25
Regulator Stations:.....325
System Pressure Zones:..... 113
Distribution Mains and Trunk Lines (miles): 7,337
Fire Hydrants:..... 60,714
Total Storage Capacity (acre-feet):.....315,245



Sustainability

Recent Accomplishment

Urban Water Management Plan

LADWP's Urban Water Management Plan (UWMP) provides a framework for developing a sustainable water future. The UWMP is updated every five years and analyzes the water supply and changes in demand for the next 25 years. The goal is to meet new demand for water through additional conservation and local resource development. LADWP is preparing the 2015 UWMP and when completed, the long-term water supply strategy will focus on:

- Expanding water conservation
- Expanding water recycling
- Enhancing stormwater capture
- Cleaning up the San Fernando groundwater basin

With the projected significant increases in conservation and local water supplies, Los Angeles expects to meet the Mayor's Sustainable City pLAn goals, including reducing Metropolitan Water District (MWD) purchases of imported water in half by 2025, and increasing local water sources to more than 50 percent by 2035.

➔ Go to **www.ladwp.com/water** to learn more.

Recent Accomplishment

Mayor's ED 5 and State Goals

As a record statewide drought continues into its fifth consecutive year, LADWP is working to meet aggressive conservation targets established by Mayor Eric Garcetti and the State to reduce water usage.

- The Mayor's Executive Directive No. 5 (ED5) calls for a reduction in water use per capita of 10 percent by July 1, 2015, 15 percent by January 1, 2016, and 20 percent by January 1, 2017.
- The State Water Resources Control Board (SWRCB) Emergency Conservation Regulation mandated that LADWP reduce water use by 16 percent from June 2015 through February 2016. The State revised LADWP's water conservation target to 14 percent as of March 1, 2016.

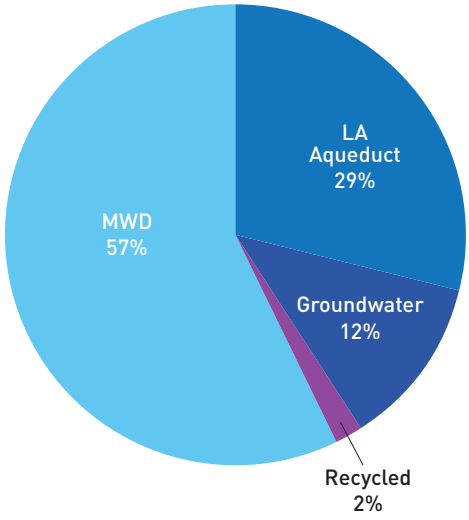
LADWP is on track to meet both of these mandates. LADWP met the Mayor's first two milestone targets for July 1, 2015 and January 1, 2016. As of the end of 2015, LA's water use was 107.6 gallons per capita, which puts LADWP on track to meet the Mayor's 20 percent reduction target. From June to December 2015, LADWP reduced water use by 16.7 percent, which exceeded the State Emergency Conservation Regulation's target. These impressive water savings were achieved through a combination of aggressive conservation outreach, increased enforcement of water restrictions, and a wide array of rebates and incentives.

LADWP has also increased efforts to replace lawns at its own facilities. As of December 2015, LADWP had retrofitted 49 facilities with water-wise landscape, totaling 406,363 square feet of turf removed and over 827,449 square feet of total California Friendly® landscaping installed.

Water Supply

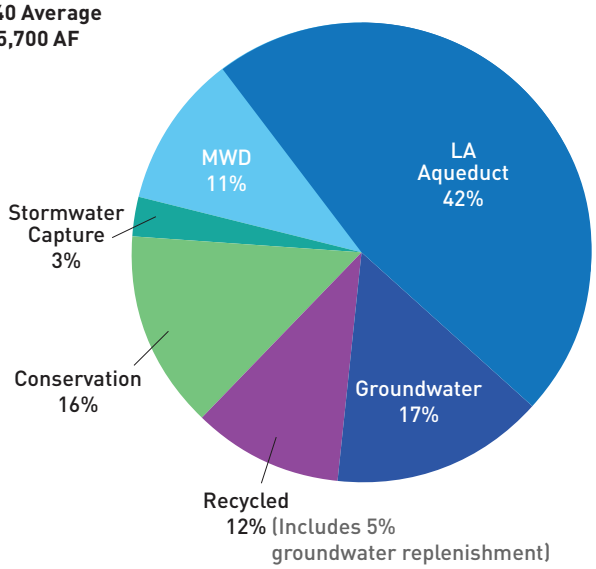
Present

FY 2011-15 Average
Total - 550,355 AF



Future

FY 2039-40 Average
Total - 675,700 AF



Recent Accomplishment

Water Conservation

With critical drought conditions persisting in Los Angeles and Southern California, LADWP continues to urge customers to use water wisely. Historically, Angelenos have a strong conservation ethic. The City of Los Angeles has long recognized water conservation as the core of multiple strategies to improve overall water supply reliability. Los Angeles has one of the lowest water use per capita levels of any major US city. Water use is about the same as it was in the 1970s, despite a population increase of over 1 million people.

Recent Accomplishment

Outreach and Rebate Programs

On April 9, 2015, the new "Save the Drop" Water Conservation Outreach Campaign was launched. This campaign is a partnership between the Mayor's Office and LADWP. Outreach materials include public service announcements, radio spots, event handouts, and signage on the sides of Bureau of Sanitation trucks. The campaign also partnered with celebrities such as Steve Carrell, Jaime Camil, and Moby for public service announcements airing on TV, cinema, and radio. The campaign focused on behavioral changes and rebates to help meet the Mayor's Executive Directive No. 5.

LADWP continues to offer a myriad of rebate options to customers to help them respond to the call to conserve water. LADWP's current rain barrel rebate is $100 per barrel, its cistern rebate is $400, and turf removal rebate is $1.75 per square foot for residential customers and up to $1.00 per square foot for commercial customers. The turf removal rebate that LADWP has offered boosted the popularity of the program tremendously, and in fiscal year 2014-15, a new record was set with 14.7 million square feet of turf removed. Since the program started in 2009, LADWP customers have removed over 43.9 million square feet of turf, including 33.5 million square feet since ED5 was issued in 2014. In 2015, LADWP residential customers' participation in water conservation rebate programs grew by 503 percent compared to 2014. Commercial rebate programs increased by 601 percent compared to the prior year.

Recent Accomplishment

Home Water Report Pilot Study

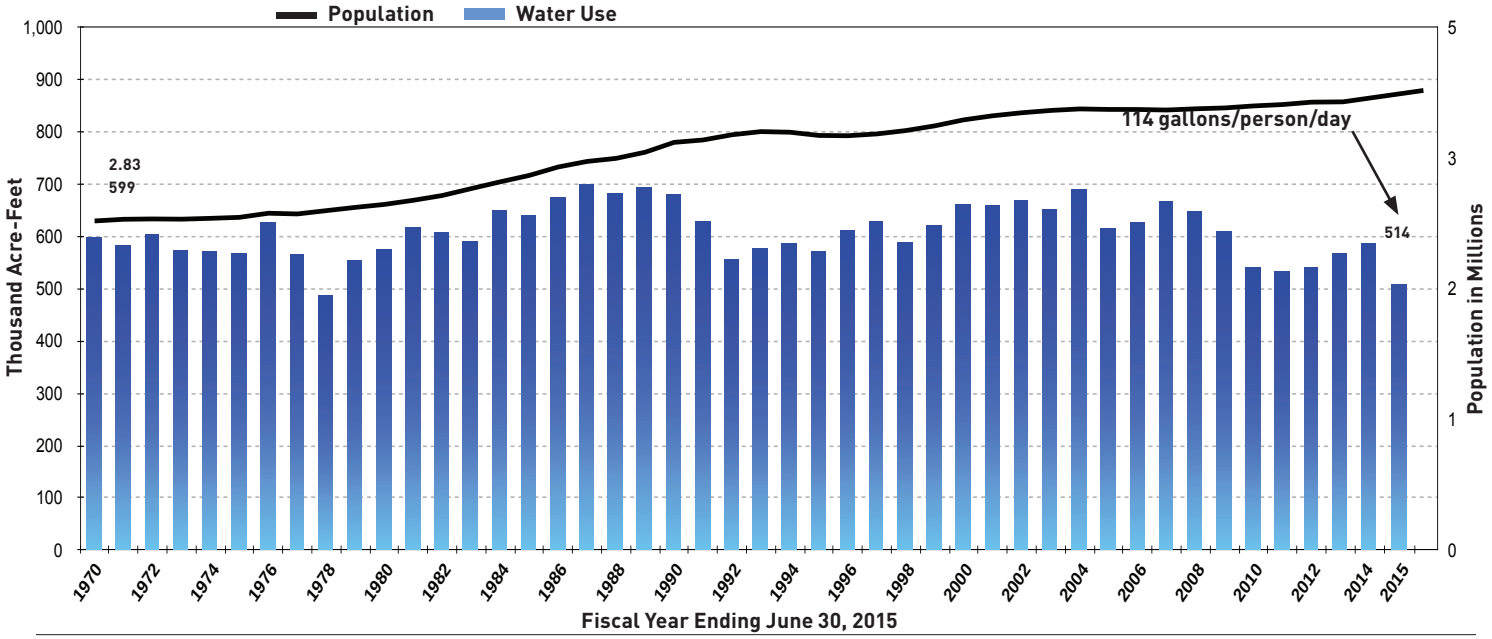
In December 2014, LADWP started its Home Water Report Pilot Study, a water conservation engagement program that provides customer-specific education and outreach. Through the program, approximately 72,000 single-family customers are receiving bi-monthly home water reports. These reports provide the customers with easy-to-understand information on their water usage, statistics on how they compare to similar households with average and efficient water use, and customized water saving tips and rebate recommendations.

After the pilot is completed in 2017, LADWP will analyze results to determine the savings potential and cost-effectiveness of the program. The results of the pilot will assist LADWP in planning a long-term program that targets all single-family residential customers.

Water Conservation Response Unit

LADWP's Water Conservation Response Unit (WCRU) has stepped up visibility by patrolling the city in bright blue cars that say "Keep Saving Water L.A.!" and actively responding to complaints about water waste. In 2015, the WCRU handled 16,848 complaints, mailed 12,244 educational warning letters, and conducted 3,173 in-person inspections.

Historic and Projected Water Use and Population



Recycled Water

Recycled water is a critical element of LADWP's local water supply strategy. Since 1960, the City has recognized the potential for water reuse and invested in recycled water treatment that meets Federal and State standards (Title 22) for non-potable water uses, including irrigation, industrial and environmental uses, and in infrastructure (commonly known as purple pipes) to convey recycled water to customers.

Under the draft 2015 Urban Water Management Plan, LADWP's proposed goal is to use 75,400 acre-feet per year (AFY) of recycled water by 2040.

Recent Accomplishment

Recycled Water Expansion

Recycled water was first used in Los Angeles in 1979 for park and landscape irrigation. LADWP used 10,421 acre-feet (AF) in 2014-15 for irrigation, industrial and seawater barrier intrusion prevention. LADWP serves recycled water to 200 customers, including Griffith Park, seven City-owned golf courses, Loyola Marymount University, Los Angeles World Airports, Valley Generating Station, Playa Vista Development, Forest Lawn Memorial Park, CalTrans, and NBC Universal. LADWP's newest customer is Hansen Dam Golf Course, which was brought online in January 2015 and aimed to save 500 AFY of potable water.

LADWP also provides about 38,000 AFY of treated wastewater to West Basin Municipal Water District to further treat and provide recycled water to municipalities in west Los Angeles County. An additional 27,000 AFY of recycled water is used for environmental purposes at Lake Balboa, the Donald C. Tillman Japanese Garden, and the Wildlife Lake.

Implementation of LADWP's recycled water program continues to move forward with the addition of new purple pipe. Agreements recently approved will expand the Terminal Island Water Reclamation Plant in the Harbor, and create new connections to Burbank's recycled water lines to provide recycled water to North Hollywood. LADWP is also evaluating a partnership with Las Virgenes Municipal Water District to provide recycled water in Woodland Hills.

LADWP is also moving forward with the Recycled Water Consumer Capital Incentive Program. This program will provide funding assistance for customers who have on-site costs associated with converting to recycled water.

Recycled Water Master Planning

In 2012, LADWP completed its Recycled Water Master Planning documents which details the Department's plans to increase the supply of recycled water to offset potable water demands. The Recycled Water Advisory Group, a caucus of engaged community members, was recognized jointly by the Board of Water and Power Commissioners and the Board of Public Works for advancing recycled water as a local, safe, and reliable supply for the city. December 2014 marked the five-year anniversary of the launch of the Recycled Water Advisory Group. LADWP and the Bureau of Sanitation actively sought stakeholder involvement during the development of the Recycled Water Master Planning documents through ongoing outreach strategies since 2009. These strategies included public forums, elected official briefings, and presentations to Neighborhood Councils and community groups.

Groundwater Replenishment

LADWP is pursuing the Los Angeles Groundwater Replenishment Project to use up to 30,000 AFY of highly purified recycled water to recharge the San Fernando Groundwater Basin. This effort will help maintain the reliability of the City's local water supply and reduce the need for imported water. The Draft Environmental Impact Report for the GWR Project was released in early 2016. Project completion is expected in 2024.

Stormwater Capture

Stormwater is an underutilized resource in Los Angeles. Capturing and reusing more stormwater is a natural way to replenish local groundwater aquifers while improving water quality in our ocean, rivers and other water bodies.

Currently, the average stormwater capture is about 64,000 AF annually. By 2035, the annual stormwater capture is expected to more than double to 132,000 AF.

Recent Accomplishment

Stormwater Capture Master Plan

In August 2015, LADWP completed the final Stormwater Capture Master Plan to guide efforts to enhance the beneficial uses of stormwater runoff as a supplemental water resource for Los Angeles.

Stormwater enhancement efforts include larger, centralized projects that will increase groundwater pumping by an estimated 15,000 AFY in the San Fernando Groundwater Basin. Smaller, localized stormwater capture projects will provide an additional 2,000 AFY.

Stormwater Projects

In partnership with the Los Angeles Flood Control District (LAFCD) and other governmental and non-governmental agencies, LADWP has completed several major stormwater enhancement projects while others are underway. A few of the major projects underway include enhancing the Tujunga and Hansen Dam spreading grounds.

Purple Pipe Bridge at Hansen Dam Golf Course

Rain barrels help capture stormwater

Hansen Dam Golf Course

Tujunga Spreading Grounds Enhancement Project
A two-year construction project is expected to begin in July 2016 to enhance the Tujunga Spreading Grounds, which is owned by LADWP and operated by the District. The enhancements will include relocating and automating the current intake structure on Tujunga Wash, installing a second automated intake to receive flows from the adjacent Pacoima Wash, and reconfiguring the existing spreading basins, among other upgrades. LADWP will provide $27 million to LAFCD for construction. Once complete, the project is expected to increase stormwater capture by 8,000 AFY.

Hansen Spreading Grounds Enhancement Project
LADWP provided $4.2 million to LAFCD to reconstruct the basins to increase the capacity and efficiency of the spreading grounds. Improvements to the intake structure were completed in January 2013, and are expected to increase average stormwater capture by 2,000 AFY.

Groundwater Cleanup

Man-made pollution, caused by industrial activities beginning in the 1940s, has severely impaired the quality of San Fernando Basin groundwater, forcing closure of over half of LADWP's production wells. LADWP is taking action to remove the contamination from the groundwater to restore the beneficial use of the aquifer, which once provided adjudicated water rights of 87,000 AFY.

To begin the remediation and cleanup of the local groundwater resources, LADWP has completed the construction of 25 groundwater monitoring wells in various areas of the eastern San Fernando Basin where the city's major wellfields are located.

The wells, along with a network of more than 70 existing wells, are being used to characterize the basin's groundwater quality in order to design and construct groundwater remediation facilities for removing contamination from the city's major wellfields in the San Fernando Basin.

Water samples collected from the production and monitoring wells were analyzed to determine the nature and extent of the pollution. The location of each well was selected in coordination with drinking water regulators to measure the water quality along specific groundwater flow paths which lead toward LADWP wellfields.

The groundwater sampling effort was completed in 2014, and the initial findings of the characterization study were determined in early 2015. Preliminary findings have been reviewed with the State Water Resources Control Board, Division of Drinking Water (DDW), and LADWP expects to seek DDW approval to construct major groundwater remediation facilities. These facilities, expected to be operational by 2021, will be designed to remove contamination from the local groundwater to protect the environment and the public.

Owens Valley

LADWP has maintained a significant presence in the Owens Valley for over 100 years. Since the early 1900s when the City of Los Angeles began purchasing land in the Owens Valley to secure water rights, the City has been the single largest landholder on the valley floor. Since construction of the First Los Angeles Aqueduct (LAA) in 1913, a major portion of LA's water supply has come from the Owens Valley.

LADWP manages nearly 315,000 acres of land in the Eastern Sierra to protect the city's watershed. Throughout the past century, LADWP has followed a consistent policy of making Owens Valley lands available for recreation, ranching, horse and mule packing, and use by businesses, schools, and public agencies.

The Water System operates and maintains water supply facilities in the Eastern Sierra, including the First and Second LAA, several reservoirs, and hundreds of miles of canals and ditches.

Recent Accomplishment

Protecting the Owens Valley Environment

The year 2015 marked the worst drought in California's recorded history, yet LADWP was able to meet its environmental commitments in the Owens Valley through some innovative engineering. After using what little water was available in the Eastern Sierra to meet its commitments in the Owens Valley for the irrigation season, LADWP removed a temporary dam it had placed in the Los Angeles Aqueduct. The earthen and concrete structure was put in place in April 2015 near the south end of Owens Lake to hold back Eastern Sierra runoff water in the Owens Valley for environmental purposes during this period of extreme drought. The first-of-its-kind dam enabled LADWP to successfully meet its environmental and other water commitments in the Owens Valley.

The total Eastern Sierra water supply on an average year is approximately 541,000 AF. Of this amount, approximately 220,000 AF are typically exported from the Eastern Sierra region to Los Angeles. The rest remains in the Owens Valley for uses including environmental mitigation, recreation, habitat enhancement, irrigation and dust mitigation on the Owens Lake, among others. Due to extreme drought, only about 27,000 AF of water gathered from the Eastern Sierra were exported to Los Angeles in 2015, which is only 12 percent of what is typically exported during a year with normal hydrology.

Lower Owens River Project

The Lower Owens River Project (LORP) is the largest river restoration effort of its kind in the United States. Begun in December 2006, the LORP encompasses re-watering a 62-mile-long stretch of the Owens River that was essentially dry after diversions into the Los Angeles Aqueduct began in 1913. In addition to creating new riverine-riparian habitat, the project also includes the 20,400 acre Blackrock Waterfowl Management Area, several off-river lakes and ponds, and the Owens River Delta Habitat Area. Since its completion, the effort has seen the resurgence of willow and cottonwood trees; songbirds, waterfowl and shorebirds are increasing in numbers; and recreational opportunities for anglers, botanists, hunters, hikers, boaters and bird watchers have also been enhanced.

Environmental Efforts on Owens Lake

Since 2001, LADWP has devoted immense financial and water resources to live up to its obligations to mitigate dust emissions at Owens Lake related to its water diversions. LADWP customers have funded the largest dust-control project in American history, covering more than 45 square miles of the lakebed with water, vegetation or gravel. The project has required massive construction, operation and maintenance efforts by LADWP—as well as over 80,000 acre-feet in 2013 alone—at a total cost of more than $1.6 billion to date. This has resulted in substantial and enduring environmental progress, leading to a 96 percent reduction in dust emissions from Owens Lake with 99 percent projected in the coming years.

Owens Lake Trails

On April 29, 2016, LADWP, along with many stakeholders and agencies in the Owens Valley, dedicated the Owens Lake Trails. A component of the Owens Lake Dust Mitigation Program, the trails will enhance public access, recreation, and wildlife habitat at Owens Lake. The project also provides public education about LADWP's dust control efforts on the lake.

➔ Go to **www.ladwp.com/losangelesaqueduct** to learn more.

Owens Lake Trails

Sea of 96 million shade balls at LA Reservoir

Safety

Water Quality

Ensuring the city's water quality meets the highest Federal and State standards is paramount to LADWP's water operations.

LADWP is investing in major infrastructure projects to meet drinking water regulations, such as the Long Term 2 Enhanced Surface Water Treatment Rule (LT2) and the Stage 2 Disinfectants/Disinfection By-Products Rule (DBP2). LADWP's major efforts to comply with these regulations include addressing its three remaining open reservoirs, enhancing the city's water supply disinfection system with UV treatment, and changing the distribution system disinfectant from chlorine to chloramine. Failure to comply with these drinking water requirements is not an option for LADWP.

➔ Go to **www.ladwp.com/waterquality** to learn more.

Reservoir Projects

LADWP has determined the path forward for bringing the three remaining open reservoirs into compliance with the LT2 water regulation. Headworks East is now online to help replace storage at Silver Lake and Ivanhoe reservoirs, and construction has begun on Headworks West. Elysian and Upper Stone reservoirs will remain in service and receive floating covers. Lower Franklin Reservoir will have its floating cover replaced and Eagle Rock Reservoir has had a new floating cover installed. Los Angeles Reservoir will also remain in service with a new ultraviolet (UV) treatment plant to disinfect water leaving the reservoir, and 96 million shade balls to assist in controlling disinfection byproducts and algae.

Recent Accomplishment

Upper Stone Canyon and Elysian Reservoir Projects

In January 2012, the Board approved the Final Environmental Impact Report for a floating cover on Upper Stone Canyon Reservoir and followed with a similar action in April 2012 for the Elysian Reservoir. After much deliberation, the Board approved the most practical and cost-effective solutions for each reservoir— floating covers which will save the Department over $100 million. Final design for Upper Stone Canyon is anticipated to be completed by April 2016. Final design for Elysian was completed in January 2015 and construction began in October 2015.

Recent Accomplishment

Los Angeles Reservoir Project

A new ultraviolet treatment facility is currently in development to disinfect water leaving the LA Reservoir and satisfy the LT2 water quality regulation with construction expected to begin in 2017. In addition, LADWP completed the deployment of 96 million shade balls on LA Reservoir to help meet the bromate drinking water standard and control algae in the reservoir.

Recent Accomplishment

Ivanhoe and Silver Lake Reservoirs

The Headworks Reservoir Complex, including East and West, will completely replace Ivanhoe and Silver Lake reservoirs' storage capacity.

Headworks East was completed in November 2014, and construction of Headworks West began in July 2015. Completion is expected by May 2018.

Recent Accomplishment

Lower Franklin Reservoir Project

LADWP is moving forward with plans to replace the old floating cover on Lower Franklin Reservoir. Expected to be in construction early 2016, the new cover will satisfy water quality requirements and improve reliability. Construction is also underway inside the reservoir to improve operation and maintenance.

Eagle Rock Reservoir Project

In December 2015, LADWP completed construction of a replacement cover for Eagle Rock Reservoir. The new floating cover, which spans approximately 360,000 square feet, replaced the deteriorated existing cover to comply with California Department of Public Health requirements.

Recent Accomplishment

Citywide Chloramination

In May 2014, LADWP expanded the use of chloramine disinfection to most of our water distribution system to comply with the new rule. Chloramine is formed by mixing chlorine and ammonia. Both chlorine and chloramine are approved disinfectants for use in drinking water by the United States Environmental Protection Agency and the California Department of Health. Due to the size and complexity of our system, the expansion was conducted in phases. Areas with the highest DBP levels were converted first. The last phase will be completed in 2017 with the conversion of the Green Meadows and Watts areas. These areas historically have lower DBP levels.

The advantages to the chloramine expansion include:

- Compatibility with purchased water from MWD
- Improving system reliability
- Providing water free of a chlorine taste or smell
- Lower DBP formation
- Longer lasting protection as the water moves through the pipes to your tap, because chloramine is more stable than chlorine

Recent Accomplishment

Grants and Loans

To help fund these large-scale projects, LADWP has been awarded approximately $956.5 million in grants and loans from the Safe Drinking Water State Revolving Fund, including $45 million in grants through the American Recovery and Reinvestment Act, and $14 million in grants from the State Revolving Fund. These awards have helped reduce the potential rate impacts to customers from these projects while improving water quality.

Reliability

Infrastructure Replacement and Upgrade

LADWP maintains a vast array of infrastructure that is critical for reliably delivering high-quality water to Angelenos. With a significant amount of pipe installed at the turn of the century, LADWP is facing challenges in keeping pace with the replacement and upgrade needs of these aging water mains and riveted-steel trunk lines.

The Water System has developed a Water Infrastructure Plan, which utilizes an Asset Management Program to prioritize efforts, develop strategies, and determine the resource needs. However, because more than 27 percent of the city's pipes are over 80 years old, and the average lifespan of an iron water main is 100 years old, infrastructure reliability challenges are imminent. Moving forward, LADWP must take additional actions to accelerate the replacement and upgrade of its aging infrastructure.

Financial Plan

Toward this end, the Water System's financial plan calls for investing over $2.2 billion in the next 10 years for infrastructure reliability. A significant amount of these expenses—about $1 billion—will go toward replacing mainlines that have undergone a thorough assessment and have been prioritized as vulnerabilities within the water distribution system. Additional expenses will be incurred to replace and rehabilitate the Los Angeles Aqueduct, tanks and reservoirs, pump stations, pressure regulating stations, system valves, water meters, as well as ancillary infrastructure required to deliver water to its customers.

Infrastructure Replacement Goals

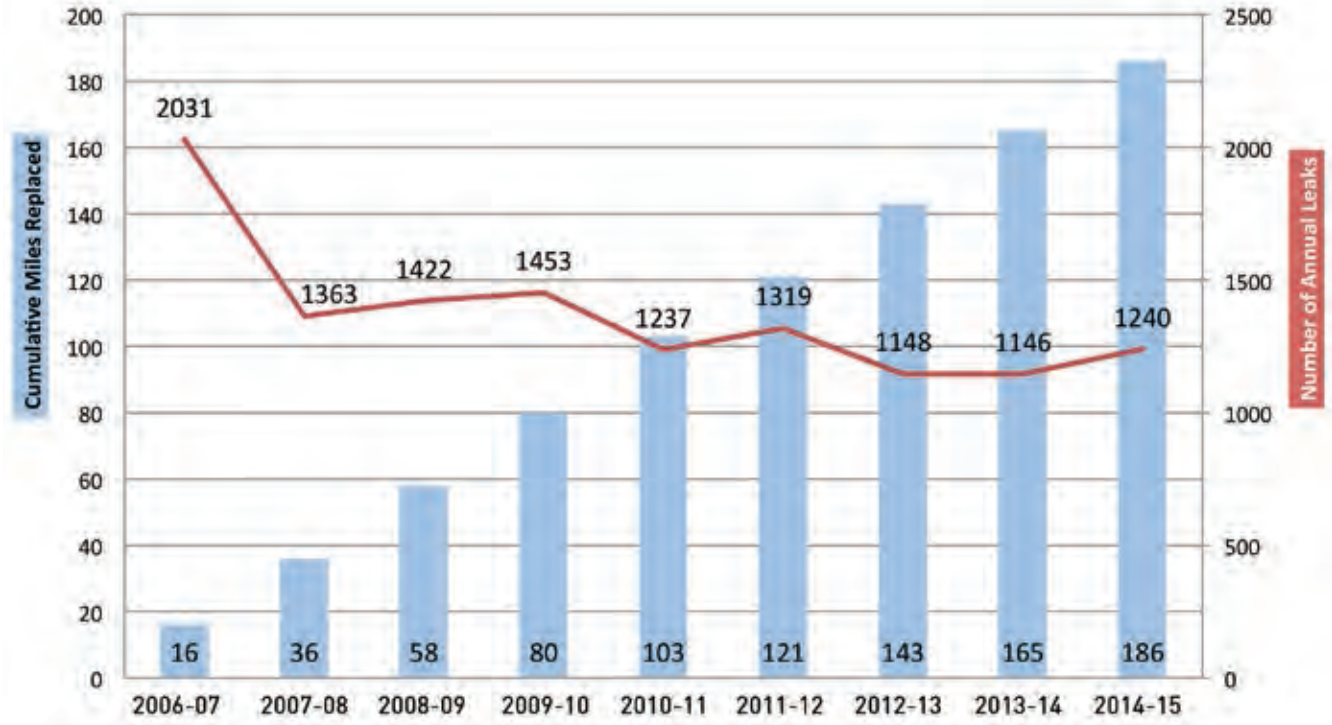
The Water System sets goals for infrastructure that are deemed critical for delivering reliable water supplies. These goals are tracked and reported on a monthly basis.

Infrastructure goals for FY 2015-16 include:

- Mainline Replacement: 150,000 feet
- Small Meter Replacement: 25,000 meters
- Large Valve Replacement: 5 valves
- Corrosion Protection Anode Stations Replacement: 200 stations
- L.A. Aqueduct Concrete Top Replacement: 15,800 feet
- Pressure Regulator Station Retrofit: 4 stations
- Pumps and/or Motor Replacement or Rehabilitation: 12 pumps/motors
- Water Tank Cleaning and Rehabilitation: 6 tanks

Significant challenges exist to replace and upgrade LADWP's infrastructure. Despite these challenges, LADWP maintains a high level of reliability, and its pipeline leak rate is below the national average of 25 leaks per 100 miles of pipeline. Through the Asset Management Program, LADWP is working to prioritize its efforts on infrastructure asset replacement and upgrade to maximize benefits and minimize reliability risks to our customers.

Mainline Replacement Program (Fiscal Year)



Crews work with Earthquake Resistant Pipe

Recent Accomplishment

Earthquake Resistant Pipe Pilot Project

On April 8, 2016, LADWP completed the installation of 6,500 feet of high-tech Earthquake Resistant Ductile Iron Pipe (ERDIP) on streets surrounding Northridge Hospital Medical Facility. The ERDIP installation is part of an LADWP pilot project that adheres to the Mayor's Resilience Plan and is only the third ERDIP project in the United States. The pipe's innovative, segmented design provides flexibility that allows up to 1 percent axial movement and up to 8 degrees rotation to deal with the strains associated with earthquakes, landslides, and temperature changes. Forces exceeding 1 percent of the pipe length cause a locking mechanism to activate to keep pipe joints from pulling apart.

With the completion of the Northridge project, LADWP has installed a total of 12,500 feet of ERDIP pipe throughout Los Angeles, all within the past three years. ERDIP pipe has been installed in the East Valley, West Valley, Harbor, Central, and Western areas of the city. Moving forward, LADWP plans to install an additional 75,000 feet of ERDIP throughout the city. These future projects will target critical facilities such as hospitals, shelters, and schools.

Water Rates and Finance

Approved in March 2016, LADWP's new water rate changes will provide necessary investments to accelerate the pace of replacing aging water infrastructure and protect against drought conditions by expanding local water sources and reducing dependence on imported purchased water.

From 2016 through 2020, a typical residential customer (using an average of 12 HCF, or hundred cubic feet, per month) will see an average increase of just over $3 on their monthly bill, or 4.76 percent per year. For all LADWP customers, including residential, commercial, industrial and governmental customers, the water rate change represents an average annual increase of 5.26 percent over the five years. During the first two billing cycles of the rate change, water rates will be slightly higher than average because of the higher cost of purchased water based an extremely low snowpack in 2015. The higher rates reflect the fact that LADWP has had to purchase significantly more, higher-priced water from the Metropolitan Water District during fiscal year 2015-16 due to the drought. The water cost is expected to be adjusted again on July 1, 2016 to reflect somewhat lower cost of purchased water based on this year's moderately improved snow levels. This will be reflected on customers' bills beginning July 1.

New Water Rate Tiers

The new water rate structure expands the rate tiers from two to four for single-family residential customers. The expanded tiers reflect the higher cost of supplying water to customers who use higher amounts. The tiered rates allow LADWP to recover the costs of providing water to high users while also having the effect of encouraging customers to conserve. The new water rate ordinance also incorporates a mechanism known as "decoupling," which allows for conservation by enabling the utility to recover fixed costs of providing basic water service. If revenues are above the sales target, the excess funds will be returned to customers. If year-end revenues are below the target, they will be recovered through a pass-through adjustment over the next year.

LADWP conducted over 80 community presentations

As with the power rates, the water rate ordinance also includes a pass-through factor to pay for water infrastructure improvements.

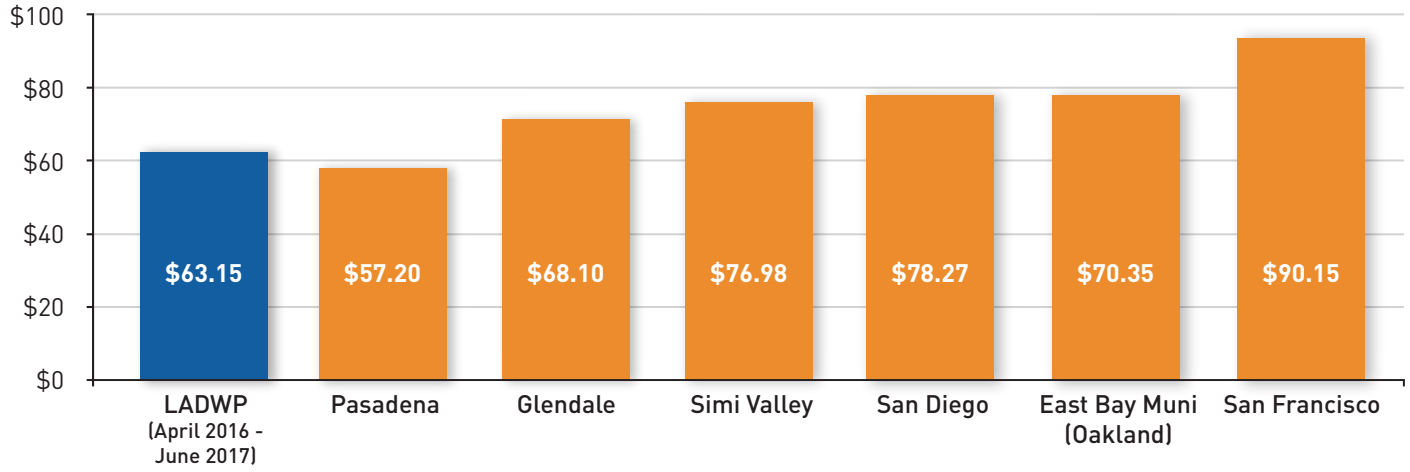
Outreach and Accountability

The water and power rates proposals were jointly presented to the public over six months starting in July 2015. Both the power and water rates include enhanced reporting requirements to improve LADWP's performance, accountability and transparency.

➔ Visit **www.myLADWP.com** to learn more.

Comparison of Typical Residential Monthly Water Bills*

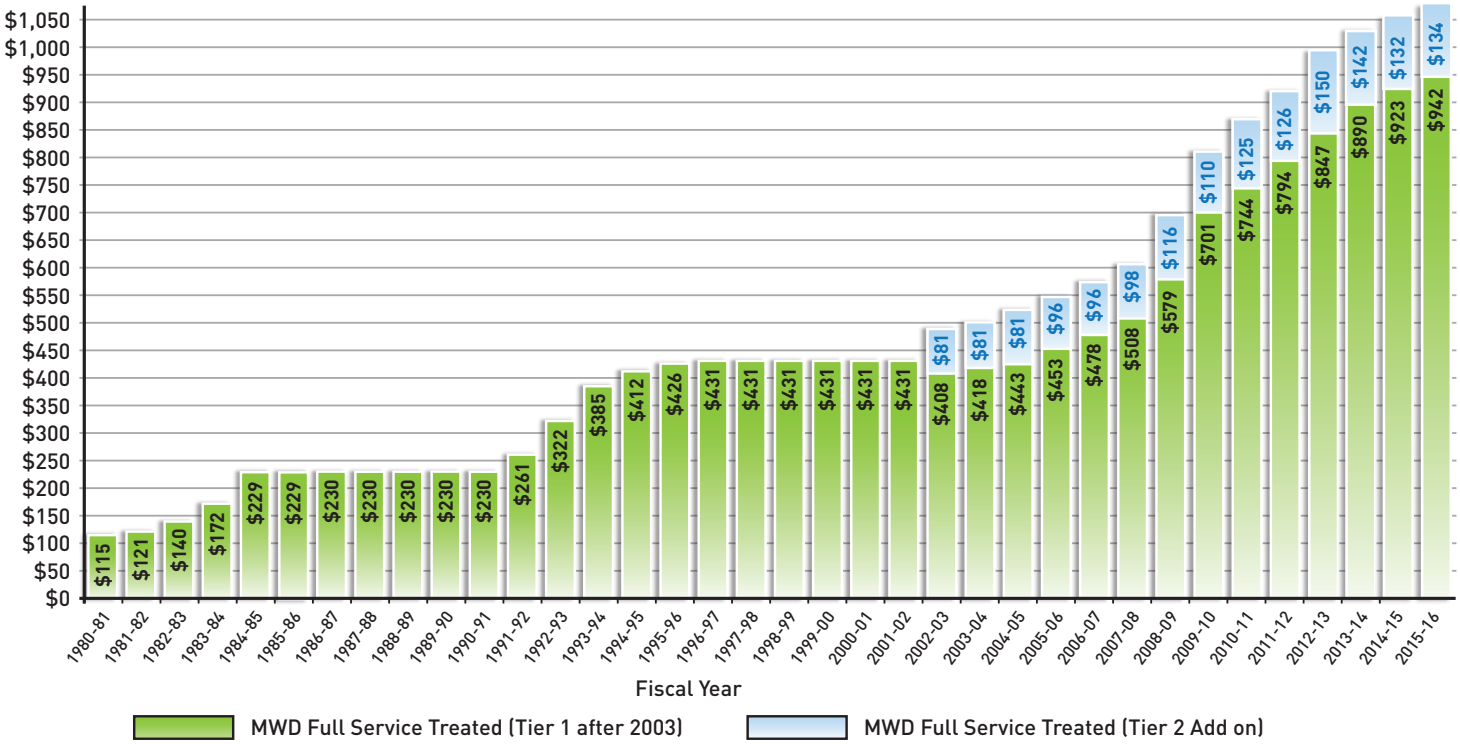
LADWP water rates are among the lowest in the region

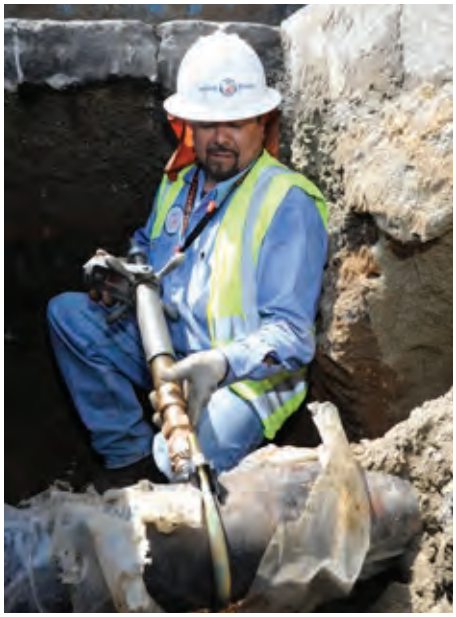


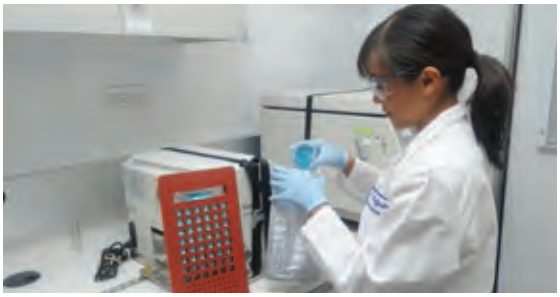
*Based on using 12 HCF/month as of March 2016

Escalating Cost of MWD Treated Water

As water supplies become less available, the price of purchased water escalates.







Customer Service

Improving the Customer Experience

The Customer Service Division embodies LADWP's customer vision by valuing the people we serve, providing respectful, responsive, and dependable customer service. Continuing to improve the customer experience for the City of Los Angeles and Owens Valley residents and businesses is a key focus of the entire Department. Customer Service takes pride in personalizing each customer interaction by striving to deliver the highest level of service in all areas.

The Customer Service Division is committed to:

- Maintaining quick turnaround times for all customer requests
- Improving customer-facing business processes across the entire Department to deliver a consistent customer experience each and every time
- Supporting the customer class action settlement terms by achieving customer metrics and correcting all inaccurate billing
- Supporting LADWP programs through our partnerships with other divisions
- Increasing visibility in the community
- Hiring and training knowledgeable and responsive employees to provide them with skills that strengthen and promote high service aptitude
- Engaging in technology improvement efforts to ensure our customers' needs are met

Recent Accomplishment

Developer Liaisons

Established in December 2015, Developer Liaison Services fills a gap by providing direct support to developers in the City of Los Angeles. While responsibilities and roles are still evolving, this new service is staffed by two full-time employees who assist large developers with meter applications, billing, and troubleshooting issues. Developer liaisons work with a variety of groups within LADWP as well as other City departments, such as Electric Service Planning, Water New Business, Department of Building and Safety, Bureau of Engineering, City Planning, and Department of Transportation.

Recent Accomplishment

Paperless Billing

The Paperless Billing initiative benefits our customers and the environment. Customers who enroll in the program receive bill notifications via email, without delay. They can view and pay their bills online, which reduces the use of paper and benefits the environment. It also reduces their paper clutter. About 201,600 customers—12.7 percent of all customers—were enrolled in Paperless Billing by the end of 2015.

Recent Accomplishment

Self-Service Transactions

Customer Service continues to increase the number of self-service transactions that customers can do online, avoiding the need to call or visit in person. LADWP continues to offer various payment options, including credit card payments and web-based payments. Customers can turn on service, turn off service, check the status of their account, set up reminders to pay their bills, and enroll in payment plans. The number of electronic payments increased by 15 percent in 2015 compared to 2014—from 441,471 to 507,604 monthly transactions. Credit card usage increased by 21 percent in 2015 compared to 2014—from 161,230 to 194,626 monthly transactions. Over 50 percent of monthly payments by customers are made electronically.

Recent Accomplishment

Training & Customer Satisfaction

Customer Service developed a centralized training program that focuses on building relationships and trust with customers, by making it easy to do business with LADWP and by having our customers' best interests at heart. Trainees receive initial training and then work—either in the Call Center or Service Centers—for a short trial period. Nearly 1,000 customer service representatives received the training in 2015. Overall, customer satisfaction for both telephone and Customer Service Center ratings significantly increased over the past year, based on call-back surveys conducted by an outside agency.

Recent Accomplishment

Dedicated Teams & Hiring

Recognizing that since many customers have needs that call for special expertise, Customer Service has set up teams to specialize in various Department initiatives, such as water conservation, electric vehicles, solar power and energy efficiency programs. Customer Service has also been hiring new staff to keep up with increased customer needs.

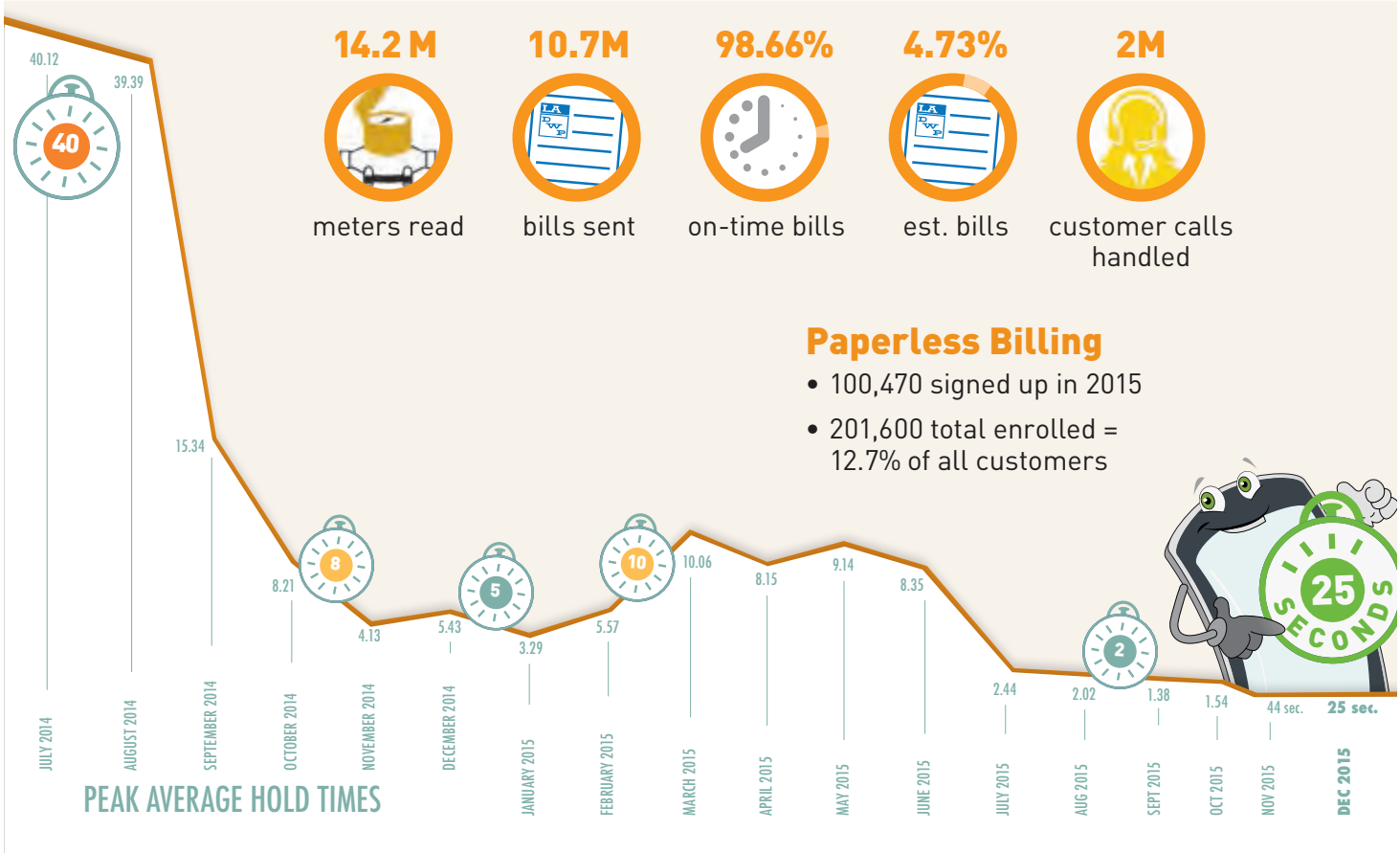
While there is a need to continue increasing staff, Customer Service has been "right-sizing" by filling over 1,000 positions since the launch of the new Customer Information System (CIS) in September 2013. These include backfilling existing vacant positions through transfers as well as hiring 260 new employees.

Customer Service Dashboard

LADWP has recovered from issues from the launch of the new Customer Care and Billing System in 2013. Since then, the Customer Service Division has met and exceeded key billing and performance standards. To foster transparency and keep customers informed of our progress, LADWP posts a weekly Mayor's Dashboard of customer service metrics. The dashboard is available at www.ladwp.com/billinginfo. Go to the box titled "How We're Fixing the Problem," and click the link for "Customer Service Dashboard Archive."

➔ Go to **www.ladwp.com/billinginfo** to learn more.

Customer Service Dashboard - 2015



Corporate Performance

In response to Mayor Eric Garcetti's goal to make City government more efficient and effective, LADWP General Manager Marcie Edwards established a Corporate Performance function in April 2014. The Corporate Performance Office works closely with the key stakeholders and LADWP operating organizations to improve the LADWP's accountability, transparency, and ultimately its performance through enhanced reporting on key performance metrics and benchmarking.

Recent Accomplishment

DWPSTAT

Initiated in August 2014, the DWPSTAT is a management accountability and problem-solving tool to assist in improving operational efficiencies. The Corporate Performance Office, working with various organizations within LADWP, has developed over 52 corporate level key performance indicators (KPIs) and dashboards for the key operations and initiatives at LADWP.

Recent Accomplishment

Benchmarking

At the request of Mayor Garcetti, the Los Angeles City Council and the Office of Public Accountability/Ratepayer Advocate (OPA/RPA), the Corporate Performance Office initiated a three-phase, comprehensive benchmarking study of the Department. Conducted by third-party consultants, LADWP's multi-phase benchmarking effort uses various comparative industry metrics to identify Departmental functions that present opportunities to improve financial and operational performance. LADWP intends to use these metrics as a road map to highlight areas where the Department meets or exceeds industry norms. The metrics also highlight underperforming areas that can be targeted for more in-depth analysis and potential performance improvement.

Completed in 2015, the initial Phase I study focused on LADWP's operating and capital expenditures on a functional level. The results showed that LADWP compares favorably to peer utilities in several significant areas, including rates, water and power reliability, and operation and maintenance costs per customer. The Phase II assessment, now under development, will provide a detailed analysis of LADWP's labor-related costs and contracting levels.

Recent Accomplishment

Industrial, Economic, and Administrative (IEA) Survey

The Los Angeles City Charter requires that the Controller, Mayor and City Council facilitate an Industrial, Economic, and Administrative (IEA) Survey every five years of LADWP to determine if the Department is "operating in the most efficient and economical manner possible." In December 2015, the Controller, in conjunction with the Mayor and City Council, concluded the 2015 IEA Survey of LADWP. The 2015 IEA Survey acknowledges much of the progress that the Department has made, its successes, future plans and detailed recommendations for consideration and action. Under the direction of the General Manager, the Corporate Performance Office will oversee the progress toward implementing the IEA Survey recommendations over the next five years.

Performance-Based Rates

One of the key recommendations from the OPA/RPA and the recently conducted 2015 IEA Survey was for LADWP to incorporate performance metrics and targets in the new Water and Power Rate Ordinances which went into effect April 15, 2016. Aimed at fostering transparency and accountability, performance-based ratemaking will require LADWP to report regularly on specific and well-defined key performance metrics to the OPA, the Board of Water and Power Commissioners, and Energy and Environment Committee. This process will help ensure that LADWP's performance is tracking with the Department's overall operational, policy, financial and strategic goals and mandates.

/LADWP @LADWP /LADWP1 /LADWP

FOOTNOTE 34

Los Angeles Department of Water & Power

L.A.'s Clean Energy Future

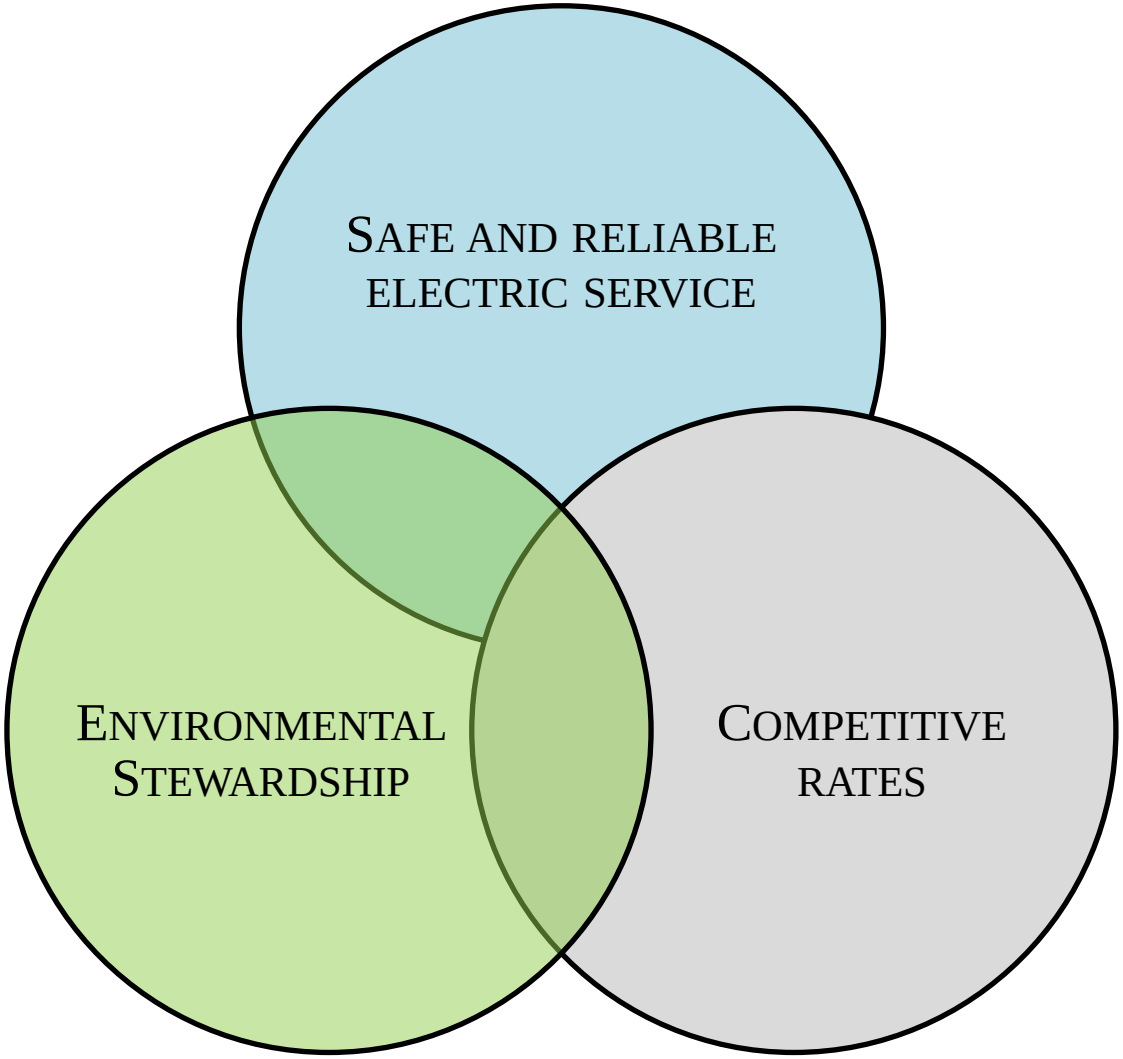
Los Angeles City Council

Energy, Climate Change and Environmental Justice Committee

August 1, 2017

Putting Customers First

Power System Objectives



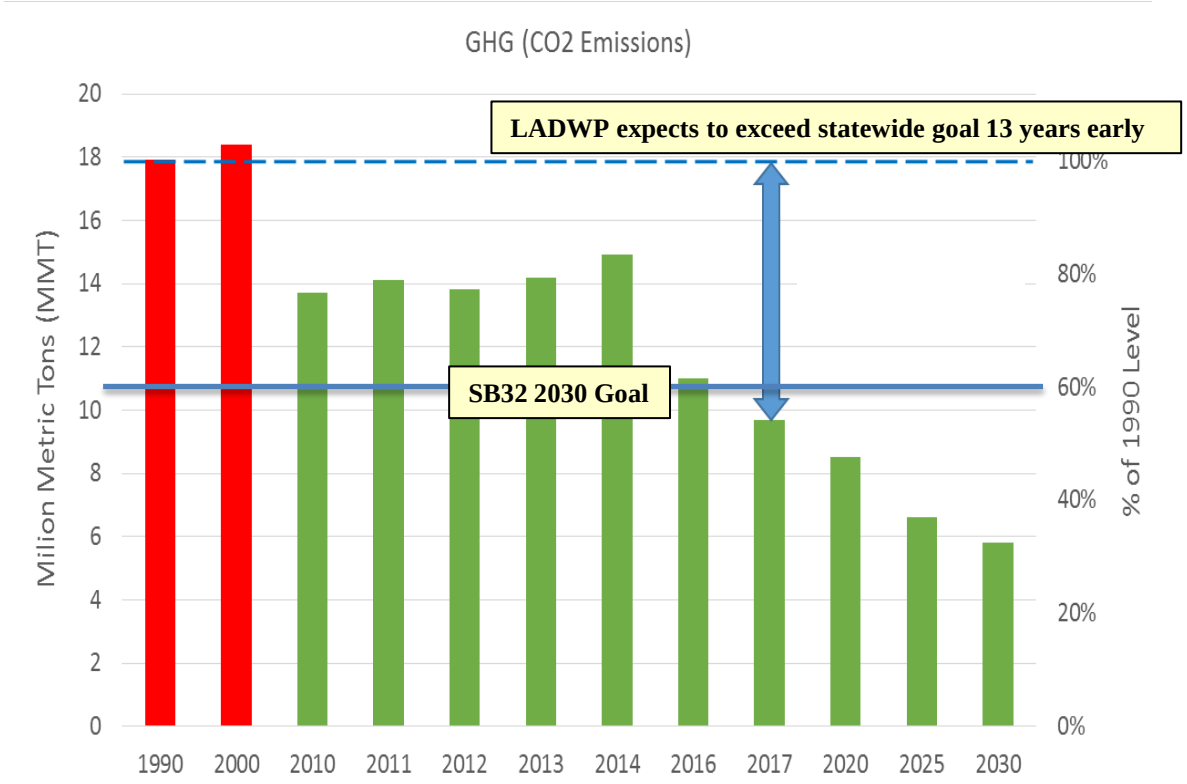
Power System Accomplishments

Year	2006	2010	2016	2020	2025	2030	2036
California RPS	-	20%	25%	33%	45%	50%	-
LADWP'S RPS Target	6%	20%	29%*	39%	50%	55%	65%

*estimated

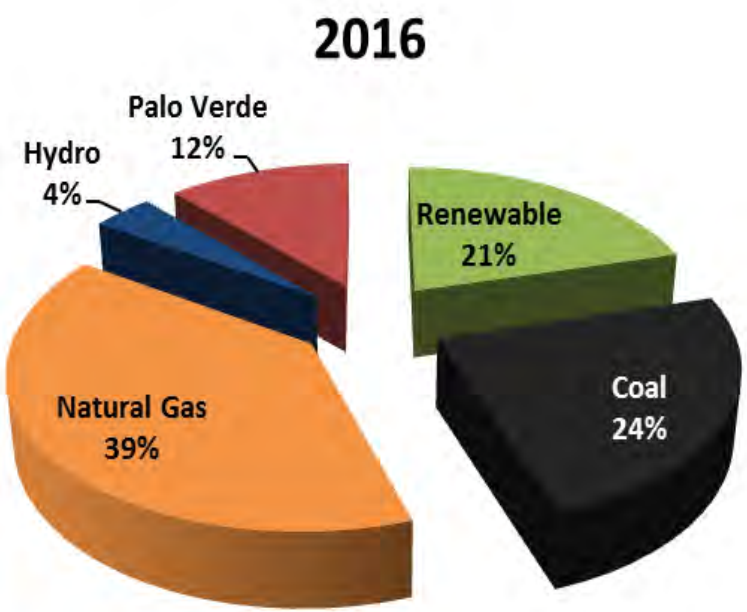
Renewable Progress:

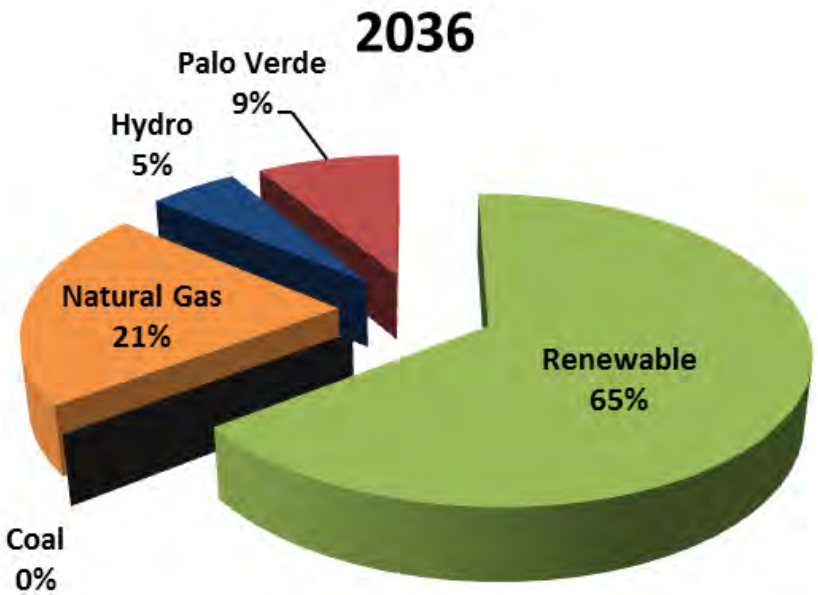
- 930 MW large solar
- 221 MW BTM solar
- 996 MW Wind
- 384 MW planned



LADWP GHG (CO2) Reductions Exceed State Mandates

2016 IRP – Transformation of Resources



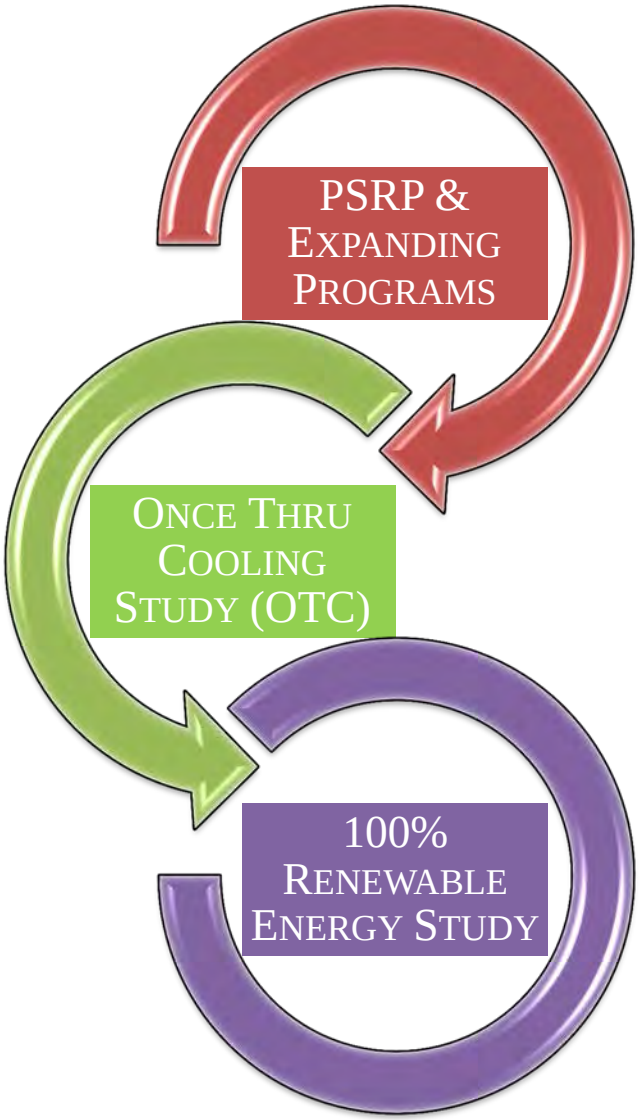


Note: *Includes 15% Energy Efficiency in 2036 in the overall mix of resources*

Power System Major Initiatives Overview

- Expanding Programs
  - Energy Storage, Energy Efficiency, Community Solar, Electric Vehicle Charging, Distributed Energy Resources, Energy Imbalance Market
- Power System Reliability Program (PSRP)
- Once-Thru-Cooling Study
- 100% Renewable Energy Study

Clean Energy Long Term Strategic Steps



Energy Storage, Energy Efficiency, Community Solar, Electric Vehicle Charging,

Distributed Energy Resources

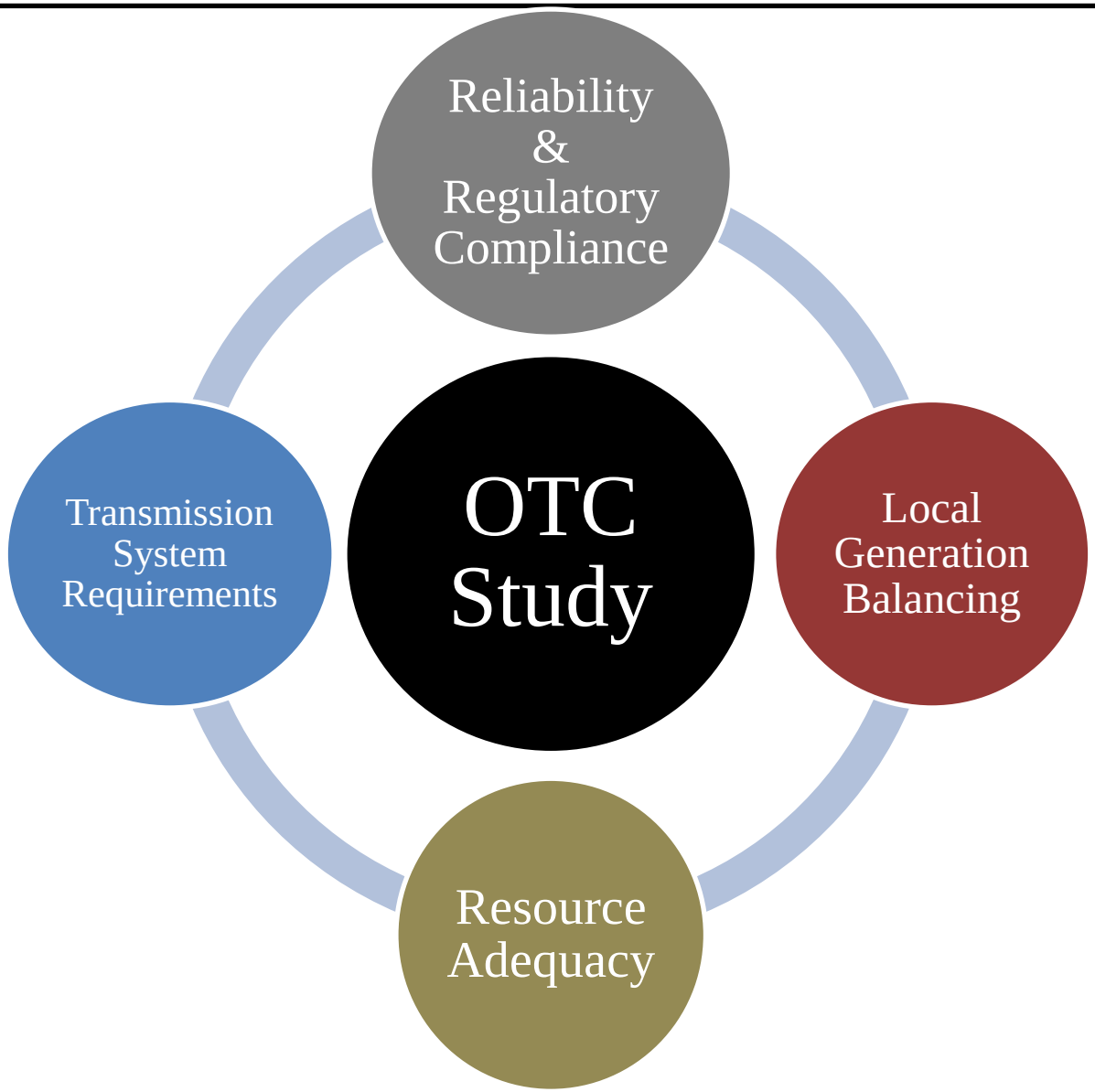
PSRP and other programs will be incorporated into the Once Thru Cooling Study. Study is currently underway by independent Subject Matter Experts and Draft Report due 1st Qtr 2018.

OTC data/modeling information will be further expanded in the 100% Renewable Study by the National Renewable Energy Lab. Establishment of partnerships has commenced. Target completion: June 2019

Replacing Aging Infrastructure

Power System Reliability Program (PSRP)			
Generation System Reliability	Distribution System Reliability	Substation System Reliability	Transmission System Reliability

ONCE THRU COOLING (OTC) STUDY



100% Renewable Energy Study

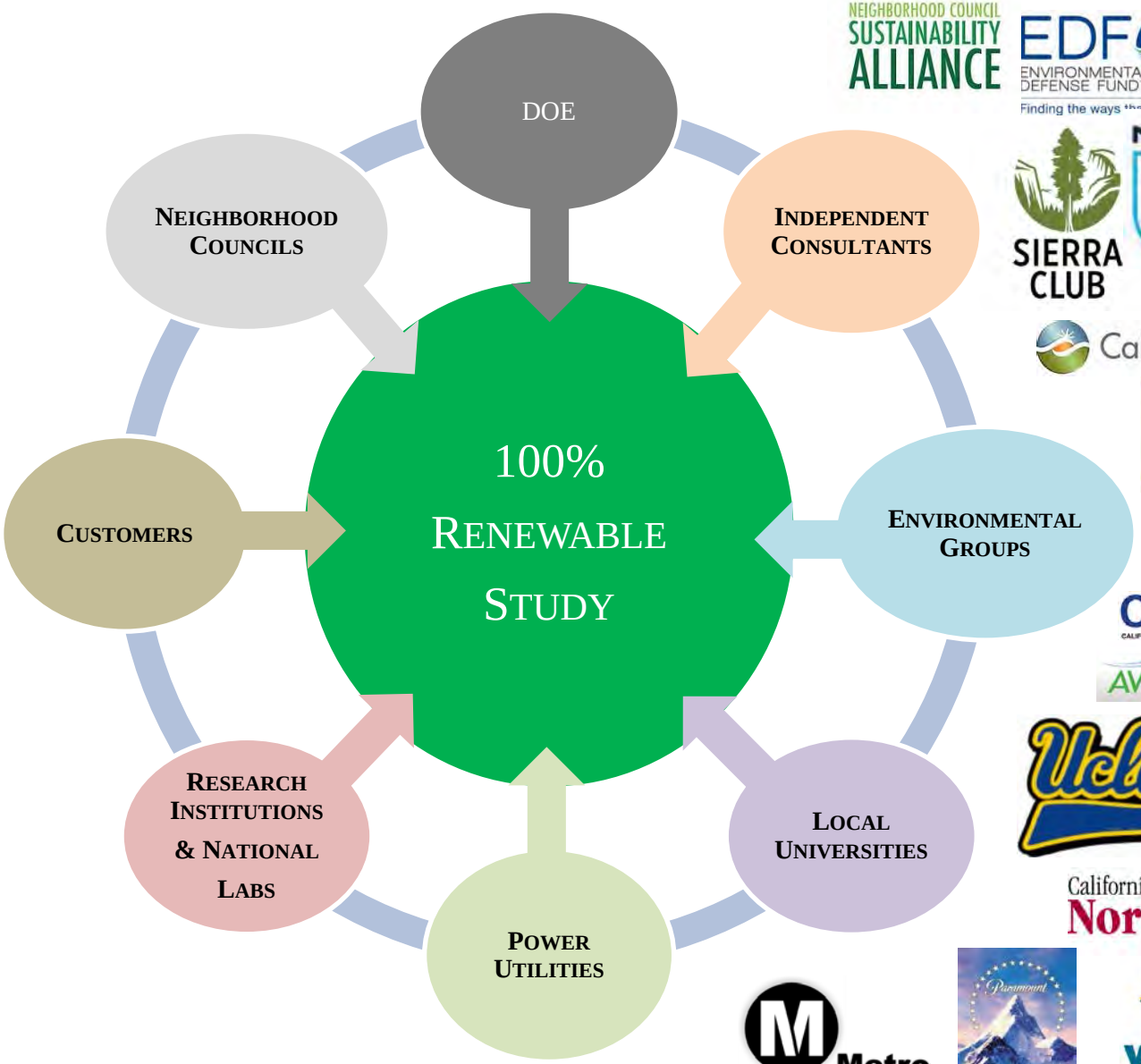
Mission Statement

Develop and implement a research partnership that will utilize technical, academic, and policy experts, as well as experts from the utility industry, to study what investments should be made to achieve a 100% Renewable Energy portfolio for the Los Angeles Department of Water and Power.

STUDY CONSIDERATIONS

- Maintaining system reliability
- Types/availability of clean energy resources
- Role of energy storage, energy efficiency, demand response, and Energy Imbalance Market (EIM)
- Developing technologies
- Necessary infrastructure upgrades
  - Critical transmission investments
  - Role of LADWP's existing natural gas generating units
  - Once Thru Cooling (OTC) Study
- Optimization of costs
- Impact to local economy
- Impact to rate payers

Study Partners



RESEARCH PARTNERSHIPS

Examine the potential for high quality careers and equitable local economic development, including local hiring programs for work that must be performed to modernize the electric system infrastructure within the City to increase efficiency, install energy storage, add distribution-connected renewable generation and otherwise enhance the electrical grid within Los Angeles.

- Macroeconomic impacts:
  - Near-term stimulus associated with the new infrastructure construction and labor.
  - What is the impact on the Los Angeles economy as a whole?
- Environmental justice impacts: what are the impacts on local air quality, and how does that impact local communities?

Next Steps

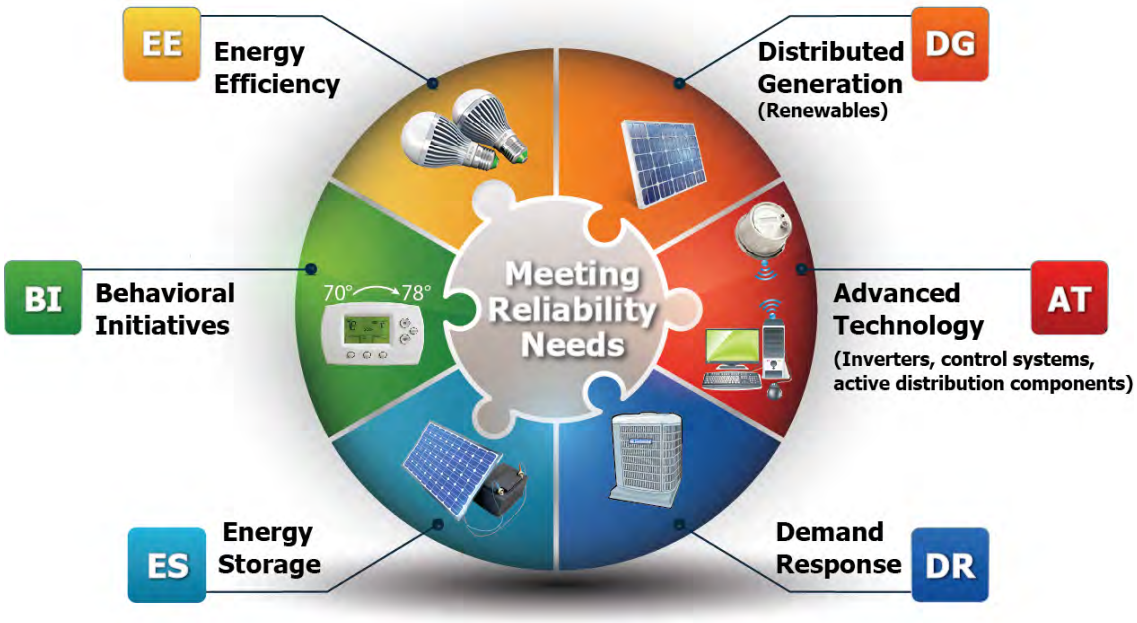
- Continue Once-Thru-Cooling and 100% Renewable Energy studies
- Continue implementation of CAISO's Energy Imbalance Market (EIM)
- Continue development of potential energy storage opportunities
- Continue to foster partnership with research institutions, academia, environmental groups, and other external stakeholders
- Expand public outreach and transparency
- Explore major opportunities in non-fossil fuel energy

Questions?

FOOTNOTE 35

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company



Preferred Resources Pilot

August 17, 2015

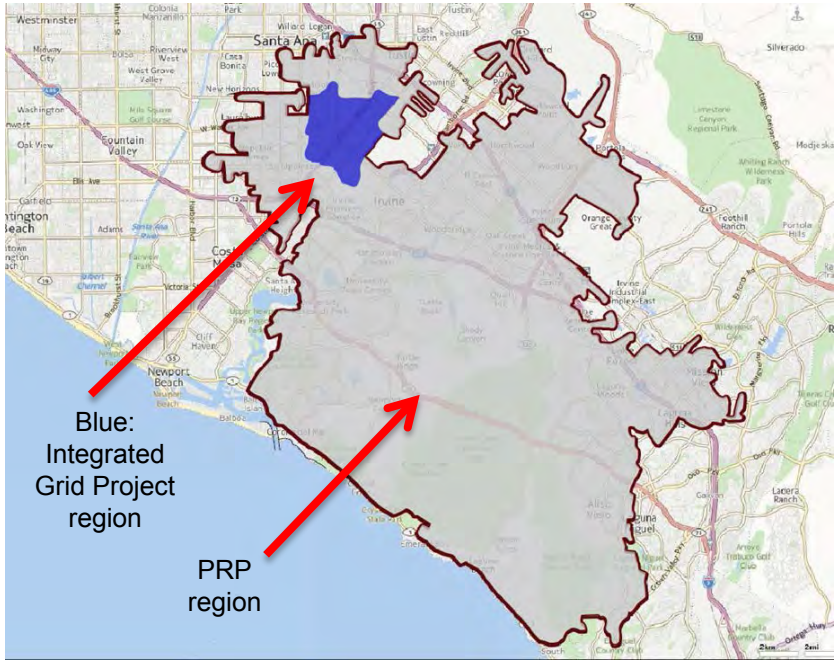
http://on.sce.com/preferredresources

http://edison.com/preferredresources

Preferred Resource Pilot (PRP) Overview

- The PRP seeks to investigate and demonstrate how the use of preferred resources (PR) may:
  - meet local capacity needs by offsetting the expected over **300 MW of load growth**
  - reduce or eliminate the need for additional natural gas fired generation (GFG) power plants
- The PRP is focused on
  - Reducing the peak load (10 a.m. – 6 p.m.)
  - Engaging commercial and industrial customers
- PRP Roadmap
  - Phase 1: Laying the Foundation (Nov. 2013 – 2014)
  - Phase 2: Demonstration and Proof (2015 – 2017)
  - Phase 3: Sustain and Close-out (2018 – 2022)

Area of Focus



- Integrated Grid Project (IGP)
  - Accelerating deployment of PR in the IGP sub-PRP region
  - Employing advanced technology, through an EPIC funded effort
  - Assessing distribution system requirements to manage high penetration of PR (also called Distributed Energy Resources - DER)

PRP Milestones and Roadmap

- Major Milestones
  - Milestone 1 - 2017/2018:
    - Demonstrate the ability to **acquire** and **deploy** a mix of preferred resources* to offset the over 300 MW of forecasted load growth
    - **Measure** the performance capabilities of those resources to defer or eliminate the need for new gas-fired generation in the PRP region
  - Milestone 2 - 2022:
    - Meet 2022 reliability needs in PRP region by using preferred resources to offset the over 300MW of forecasted load growth
- Phase 1: Lay Foundation Nov 2013-2014
  - Defined initial local specific electrical supply needs and designed resource portfolios to meet needs
  - Developed and began implementation of resource acquisition strategy
  - Established grid-level measurement processes for solar and DR

* Preferred resources include energy efficiency (EE), demand response (DR), renewable distributed generation (DG) such as solar, and energy storage (ES)

PRP Roadmap (continued)

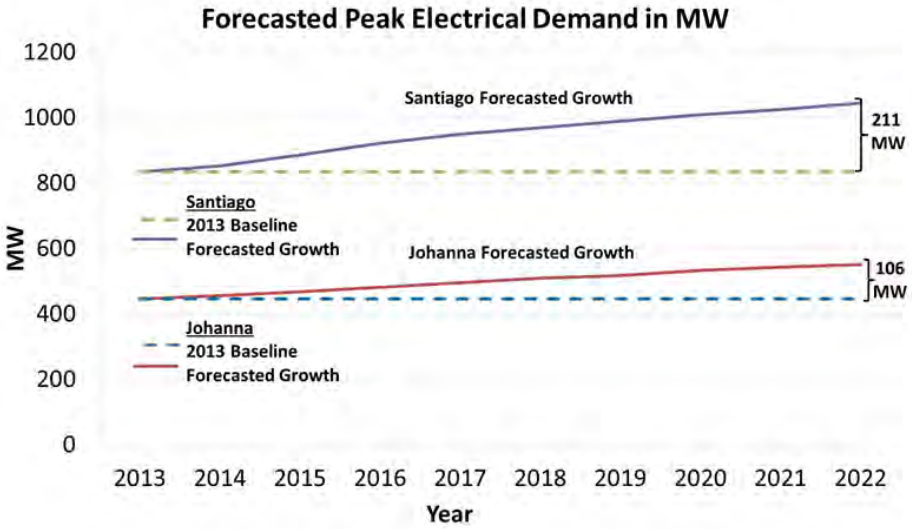
- Phase 2: Demonstration and Proof 2015-2017
  - Continue building the pipeline of resources using the acquisition strategy
  - Test integrated and tactical use of preferred resources
  - Ready the PRP distribution system (grid) for higher penetration of PR
  - Evaluate effectiveness of acquiring right mix of PR
  - Evaluate delivery capabilities of PR
  - Confirm if PR can offset load growth

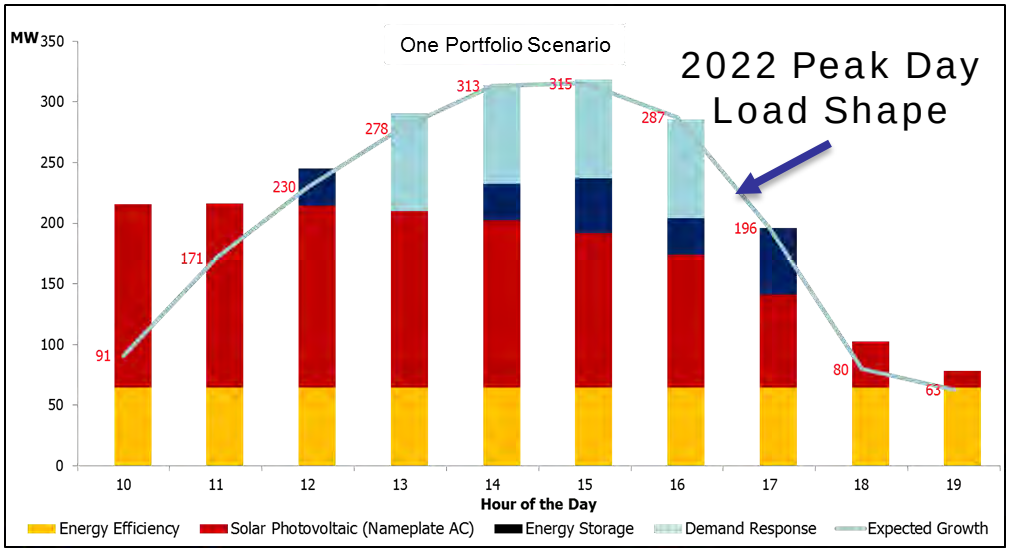
- Phase 3: Sustainability 2018-2022
  - Make determination on PR ability to meet projected 2022 need and ability to continue to defer new GFG need
  - Implement any changes to acquisition plan to meet 2022 need
  - Develop and implement program and process changes to support PR meeting 2022 forecasted need

PRP Location Specific Analysis

Bottom up Approach

- Customer load growth was determined using local specific data
- Peak months were identified as June through September
- Forecasted incremental* **2022 peak day load shape** was used to determine the PR attributes
  - Daily MW need
  - Hourly duration of need
  - Annual frequency of need
- Portfolio scenarios were developed based on the different delivery capabilities, limitations, and market potential for each type of preferred resource



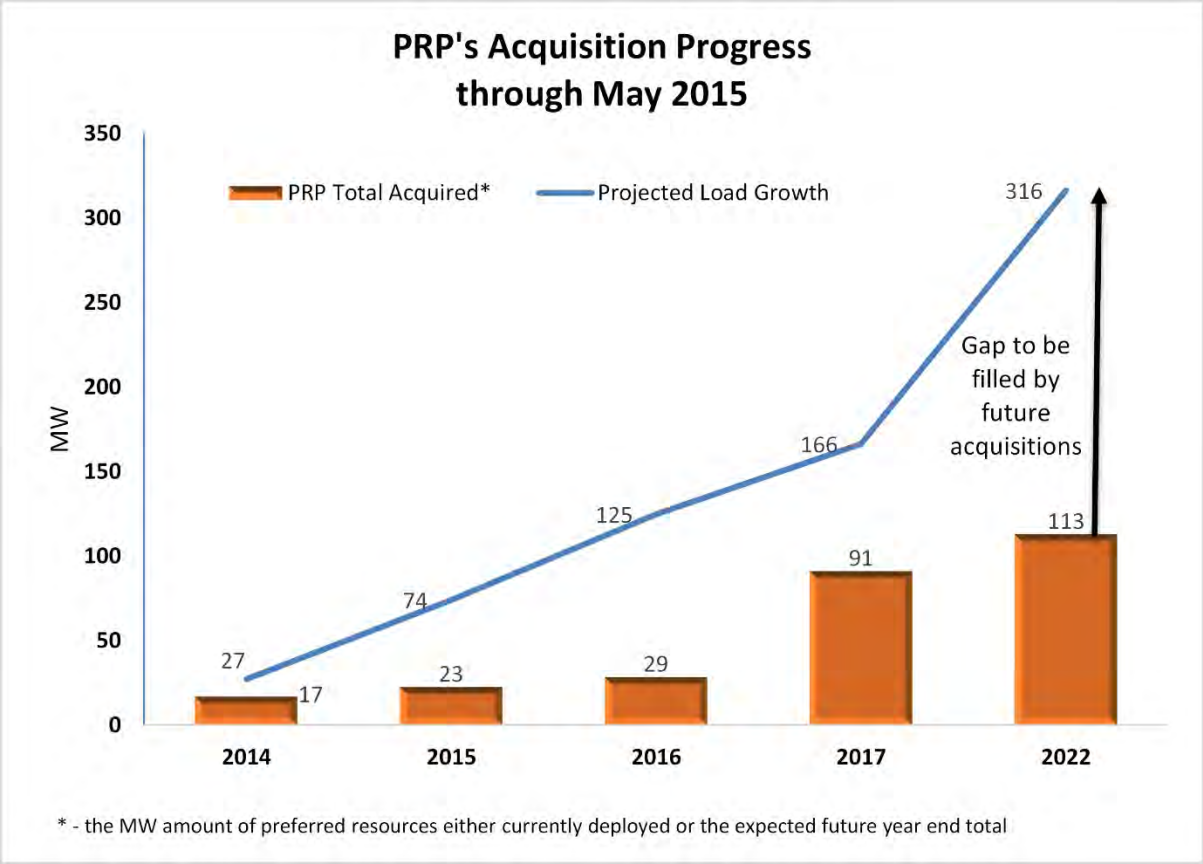


Several different combinations of preferred resources can serve the peak

* - the incremental load is the difference between the 2013 peak load to the expected 2022 peak load

PRP Milestone 1 Status - Acquire

- 113 MW have been acquired toward the current 316 MW target
  - Additional acquisitions are planned for a mix of preferred resources that can serve the expected 2022 peak load shape
- 91 MW are expected to be deployed by year end 2017; The source of these MW include:
  - ~67.4 MW from solicitations (LCR & SPVP RFOs)
  - 1 MW of ES (0.5 MW SCE owned & 0.5 Ma vendor owned)
  - ~23 MW already deployed by customers



- The 2017 mix of preferred resources include:
  - EE: 31 MW
  - DR: 31 MW
  - Solar: 25 MW
  - ES: 1 MW

PRP Milestone Status - Deploy

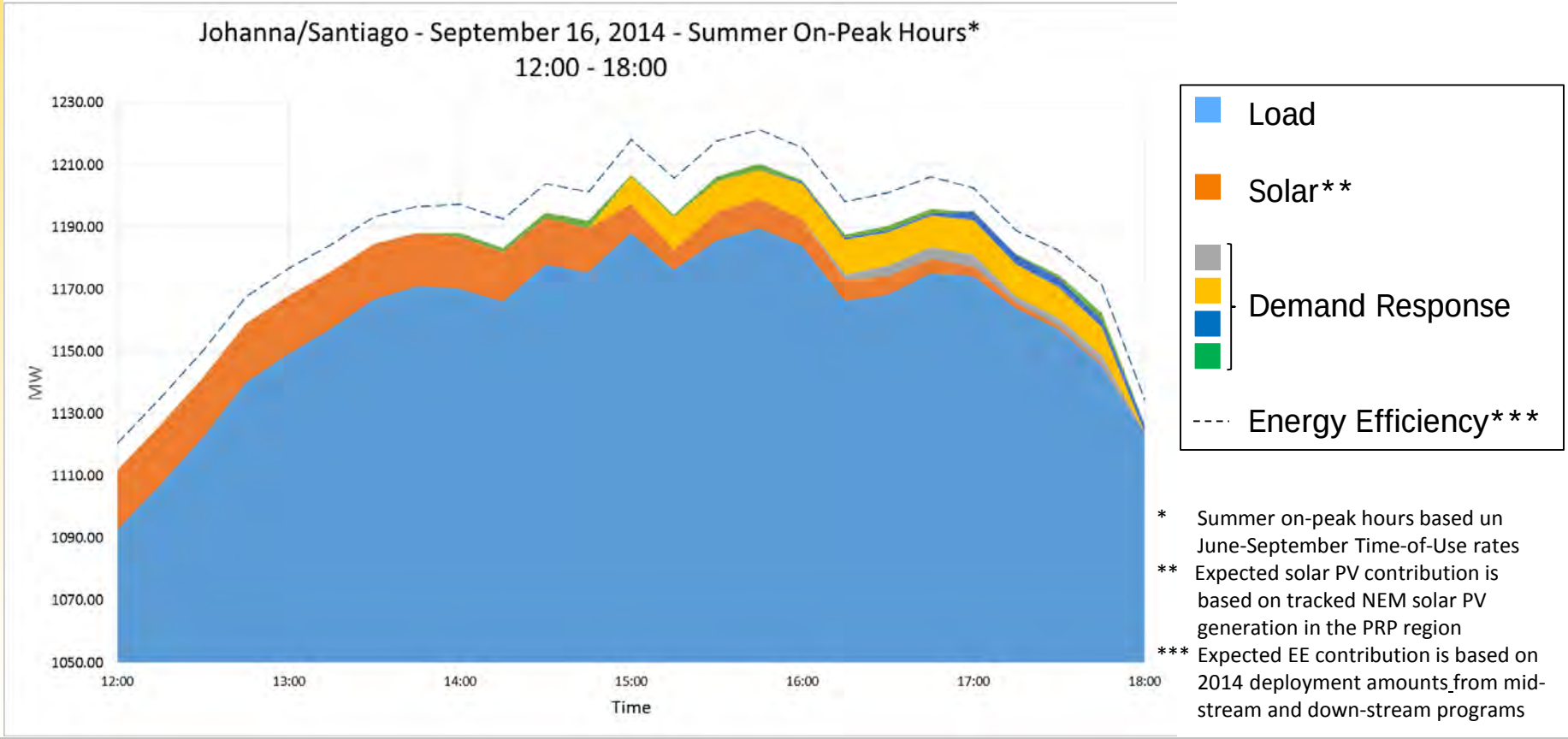
Deployed Preferred Resources (MW through May 2015*)			
Resource	2014 (actuals)	2015 / Target	Total
EE	8.5	2.5 / 8.0	11.0
DR	0.0	0.0 / 3.0	0.0
DG - CA Solar Initiative (CSI) program	6.3	0.4 / 4.6	6.7
DG - non-CSI	2.3	3.1	5.4
*MW deployed of the total 91 expected by year-end 2017			23.1

- Near-term deployment achievements are from
  - SCE's customer programs – EE and DG (CSI)
  - Customers adoption of solar without CSI
- Utility customer demand response programs pose some challenges
  - Heavy customer recruitment in 2012 to DR programs following the SONGS shutdown limits the ability to enroll new customers
  - Current utility DR programs are not designed to contract with customers for delivery in 2022 and beyond
    - Power purchase agreements with longer term commitments may provide a solution

PRP Milestone Status - Measure

- SCE is measuring preferred resources to confirm they are available when called upon (dependable), can deliver an expected load reduction or production (predictable), and can deliver in future years (persistent)

- Graph below illustrates how the PRP region's load was reduced by the contributions from solar, demand response and energy efficiency products



* Summer on-peak hours based un June-September Time-of-Use rates

** Expected solar PV contribution is based on tracked NEM solar PV generation in the PRP region

*** Expected EE contribution is based on 2014 deployment amounts from mid-stream and down-stream programs

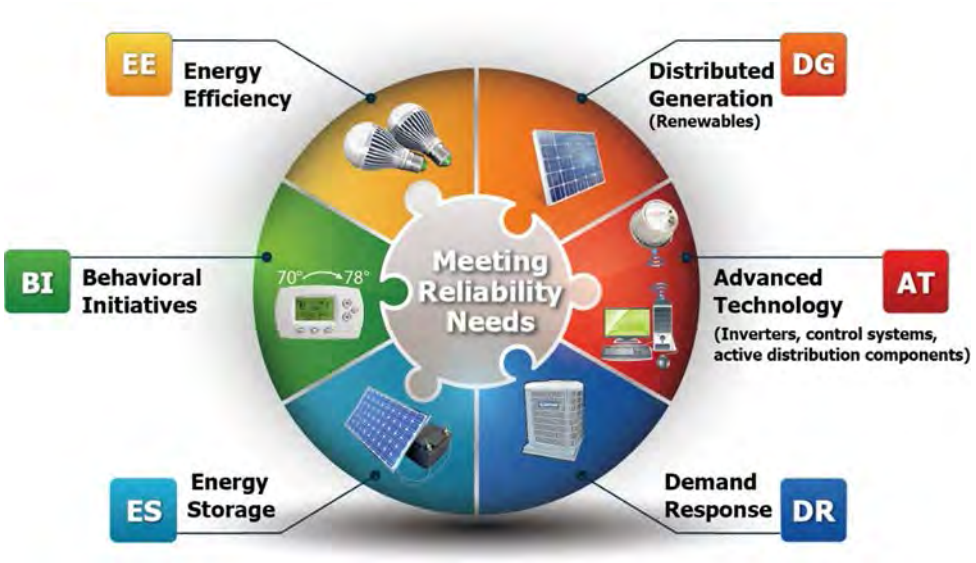
PRP Challenges

The PRP continues to explore solutions to most effectively use preferred resources. Examples include:

- Improving participation rate of commercial property owners/customers and institutional customers
  - Improving the solar and demand response participation rate
  - Resolving owner/tenant barriers
- Preparing/reinforcing the PRP area distribution system (grid) to support higher levels of preferred resources and locational benefits
- Creating local reliability products
  - More reliability DR to complement price-responsive DR
  - EE that may help to defer or avoid distribution-level investment
- Optimizing energy storage integration in constrained areas
- Integrating the region-specific measured performance results of preferred resources into grid planning processes

SCE's Preferred Resources Pilot

Demonstrating our commitment to keeping electricity safe, reliable, affordable, **and clean** today and for the future.



Working to Meet Local Peak Demand Needs and Local Capacity Requirements

Questions?

FOOTNOTE 36

EDISON INTERNATIONAL®
Energy for What's Ahead℠

STORIES THE GRID

3

O.C. Pilot Tests Whether Clean Energy Resources Can Meet Growing Needs of Major Metro Area

SCE contracts for 125 megawatts of power, including battery storage and solar.

By Paul Griffo | September 09, 2016

Southern California Edison contracted on Thursday for an assortment of clean energy resources that will be used in a groundbreaking attempt to see whether those resources can supply electricity to meet

the growing demand in a densely-populated area — Orange County — with the same reliability as a traditional power plant.

The **Preferred Resources Pilot**, as the project is known, is taking place in a wide swath of Orange County that is home to approximately 250,000 residential customers and 30,000 businesses.

“The question of whether clean energy resources can be used to safely, reliably and affordably serve the electrical needs of customers in a real-world environment is an important issue for utilities, policymakers and **energy provider**,” said SCE’s Caroline McAndrews, the project’s director. "The need for electricity in this area is increasing, and we want to meet those new needs with clean energy resources."

Contracts were signed with six developers for 125 megawatts of power representing an assortment of battery storage, “demand response” and the combination of solar and battery storage resources. Demand response means customers reduce their use of electricity from the power grid in response to an electronic signal.

These **clean energy resources** are expected to come online between 2019 and 2020 and will add to the 136 megawatts of “preferred” clean energy resources that have already been acquired for the pilot. A megawatt is enough electricity for approximately 750 homes.

“We want to find out whether these resources can reliably meet the needs of a metropolitan area, delivering the energy that is needed, when it is needed, and for as long as it is needed,” said Colin Cushnie, SCE vice president for Energy Procurement and Management. “This pilot is helping us move forward in development of a **grid of the future** that will support use of clean energy technologies and help us meet our state’s environmental goals.”

The **boundaries of the study** will encompass all or parts of the cities of Irvine, Tustin, Santa Ana, Newport Beach, Aliso Viejo, Corona del Mar, Costa Mesa, Laguna Beach, Laguna Woods, Laguna Hills, Laguna Niguel, Lake Forest and Mission Viejo.

The multiyear study is designed to determine whether these preferred resources — including solar, wind, battery storage, energy efficiency and energy conservation — can be used to offset the increasing demand for electricity in Orange County.

Developer	**Product**	**Capacity (MW)**	**Term (Years)**	**Commercial On-Line Date**
AMS	Demand Response from Energy Conservation and Battery Storage	40	15	Jan. 2019 – Jan. 2020
Convergent	Battery Storage	35	20	Dec. 2019
Hecate	Battery Storage	15	10	Jan. 2020
	Battery Storage	10	15	Jan. 2020

NextEra	Demand Response from Energy Conservation and Battery Storage	10	15	June 2018 – June 2019
NRG	Hybrid of Solar and Battery Storage	10	15	April 2019 – August 2019
Swell	Demand Response from Battery Storage	5	15	June 2019
TOTAL:		**125**	**-**	**-**

Tags: Preferred Resources Pilot, **clean energy**

Leave a Comment

We welcome your feedback and comments. We ask that you please keep them constructive, civil and respectful. If you wouldn't say it in front of your mother, then there is a good chance it falls outside of our guidelines. **Please read our comment policy here.**

Full Name

Email Address

Comment

I'm not a robot

reCAPTCHA
Privacy - Terms

Submit

Comments (3)

T. J. JOSEPH

A study that goes with the present trend. I am sure the study will come out with excellent conclusions to decide upon

960

Krause, Erik

From: edina tanacs <edina1981@yahoo.com>
Sent: Monday, November 20, 2017 9:10 AM
To: Krause, Erik
Subject: Stop Grayson project

Re: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 960-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 960-2

Edina (Glendale resident)

Sent from Yahoo Mail on Android

961

Krause, Erik

From: Eliza Maher <ehmaher@gmail.com>
Sent: Monday, November 20, 2017 9:17 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson opposition

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 961-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 961-2

Regards,

Eliza Maher,
Koreatown, Los Angeles

962

Krause, Erik

From: Elizabeth Williams <eramamama@gmail.com>
Sent: Monday, November 20, 2017 12:23 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 962-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 962-2

Regards,

Elizabeth Williams
Glendale, CA 91208

Sent from my iPhone

963

Krause, Erik

From: Ellen Martirosyan <elenjina@yahoo.com>
Sent: Monday, November 20, 2017 2:39 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 963-1

As a long time Glendale resident, I am concerned about the air pollution and direct effects of it on our future generation's health! 963-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 963-3

Regards,

Ellen Martirosyan, Glendale CA

Sent from my iPhone

964

Krause, Erik

From: Ellen <ellenr6@yahoo.com>
Sent: Monday, November 20, 2017 8:15 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Oppose Grayson

To: ekrause@glendaleca.gov, vgharpetian@glendaleca.gov, pdevine@glendaleca.gov, vagajanian@glendaleca.gov, zsinanyan@glendaleca.gov, anajarian@glendaleca.gov

Dear Mr. Krause et al,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR My family and I live close to the proposed area and are already subjected to high pollution from freeway and landfill traffic etc... 964-1 964-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 964-3

Regards,
Ellen Readinger

Sent from my phone

965

Krause, Erik

From: emily greene <emiliaverde@gmail.com>
Sent: Monday, November 20, 2017 11:56 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson repowering project

Dear Mr. Krause,
I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 965-1
I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale.
This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 965-2

Regards,
Emily Greene
Glendale constituent

966

Krause, Erik

From: Emily O'Halloran <emilysohalloran@gmail.com>
Sent: Monday, November 20, 2017 10:48 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Gas Plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 966-1

I have a small child and am very concerned about the harmful effects of this on him and our health, living so close to this. 966-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 966-3

Regards,

Emily O'Halloran, Atwater Village

(Concerned mother)

967

Krause, Erik

From: Ericka Kreutz <eckreutz@gmail.com>
Sent: Monday, November 20, 2017 8:03 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Stop Grayson Please

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 967-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 967-2

Regards,

Ericka Kreutz
Los Feliz, CA 90027

968

From: Erik Yesayan <yesayan@gmail.com>
Date: November 20, 2017 at 5:56:45 PM MST
To: "Krause, Erik" <EKrause@glendaleca.gov>
Subject: Comment on Grayson EIR

Hi Erik,

I would like to submit the attached letter as a comment to the EIR of the Grayson Power Plant. 968-1

Thanks,
Erik

November 20, 2017

RE: Comments on the Grayson Power Plant Repowering EIR

Dear Mayor Gharpetian and Councilmembers:

We the undersigned, members of the engineering, scientific, and urban planning communities, represent a broad spectrum of opinion on sustainability and energy issues facing communities throughout California. We are concerned with the current $500 million proposal by the city of Glendale to repower the Grayson Power Plant to one with increased capacity [267 megawatts (MW) raised to 310 MW], that is again powered by "natural gas" (*i.e.*, methane) at a time when power demand in the City is projected to decline and the state is increasingly regulating fossil fuel power generation.

The energy markets are currently going through a transformative shift. The scope and scale of state policies on renewables and regulation of fossil fuel generation is growing nearly as rapidly as the price of renewable energy is falling: in the case of solar, the cost for residential, commercial and utility projects declined an incredible 73% between 2010 and 2016. Emerging technologies in energy storage and efficient renewables will further change the industry.

The continued commitment to power generation by use of a fossil fuel for the thirty-year projected lifetime of this new plant (approximately July 2021 through June 2051) will also come at a time in the world's global-warming trajectory. Reliable, peer-reviewed studies and simulations of the consequences of an average global temperature rise of 1.5 degrees centigrade above pre-industrial levels show that the greater Los Angeles area will be threatened by more severe wildfires and longer periods of drought[1]. At present warming rates, the need to stay within 1.5°C demands immediate and rapid reduction in greenhouse gas (GHG) emissions. These same simulations show that, unmitigated, the Earth will reach the 1.5°C level by 2030, and the 2.0°C level by 2045. And hence, it appears that the upgraded Grayson Plant will go too far in contributing GHS emissions.

It is also disconcerting that the upgraded Grayson will emit GHGs at levels exceeding the California limit of 75,000 CO_2 equivalent tons/year. The Grayson Environmental Impact Report (EIR) side-steps this increased pollution for Glendale residents by offsetting it with Emission Reduction Credits – a move that will benefit those outside Glendale, while children and the elderly, the most vulnerable members of our community, will breathe more pollution.

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[1] See study published at Geophysical Research Letters – an AGU Journal- http://onlinelibrary.wiley.com/doi/10.1002/2015GL064924/full

We applaud the Glendale City Council in adopting a resolution earlier this year to join other cities in support of the UN Paris Climate Agreement. In keeping with the spirit of the agreement, we urge the City Council to pause further development of the repower and immediately commission an independent Cost-Benefit Analysis of the project. This analysis should include items such as Glendale's deriving renewable power from electrical grids that connect with solar-, wind- hydroelectric-, and nuclear-generated sources; estimating the harm to Glendale citizens by having to breathe CO_2, unburnt/leaking CH_4, and the non-GHG pollutants generated by Grayson; studying the costs of EPA- or state-mandated raising of emission standards for California as we approach the 1.5°C global-warming threshold; and the benefits in saving its residents the burdens of higher electrical bills and costs of a $500 million bond.

We hope the Glendale City Council will make the right decision to minimize exposure to risk for ratepayers and protect the air quality of the City. These are also imperatives of a science- and fairness-based policy that can deliver on the UN Paris Climate Agreement.

Sincerely yours,
(names in alphabetical order)

Dr. Arineh Arzoumanian
Engineering Instructor,
Pasadena City College

Alek Bartrosouf
Assistant Regional Planner,
Southern California Association of Governments (SCAG)

Biayna Bogosian
PhD Candidate
Adjunct Professor of Architecture,
University of Southern California

Dr. Ara Chutjian
Research Experimental Physicist
California Institute of Technology (Ret.)

Rafi Halajian
Senior Project Engineer,
Hathaway Dinwiddie

Natalie Kamajian
Associate, Leadership for Urban Renewal Network (LURN)

Richard Ohanian
Robotics Electrical Engineer,
Jet Propulsion Laboratory
Adjunct Faculty of Engineering,
Glendale Community College

Tarenig Topjian
Founder,
Have A Go

Zirair Tourgoutian
Principal/Program Manager,
Standard Engineering and Construction

Erik Yesayan
Manager, Cypress Creek Renewables
Former Chair of Glendale Planning Commission

969

Krause, Erik

From: Erika Edgerley Robbins <e.edgerley@gmail.com>
Sent: Monday, November 20, 2017 3:40 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Please reject plants to rebuild the Grayson natural gas power plant

Dear Mr. Krause, As a Glendale resident, I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. Thousands of people live and work directly within the Grayson project's impact zone. It's time to invest in an energy grid that can improve Glendale's already terrible air quality -- not make it worse. 969-1 969-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 969-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 969-4

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 969-5

Regards,
Erika Edgerley Robbins

--

Erika Edgerley Robbins

1010 Raleigh St. #214
Glendale, CA 91205
e.edgerley@gmail.com
c: 310.560.9227

970

Krause, Erik

From: Erika Egede-Nissen <Erika.Nissen@caesarstoneus.com>
Sent: Monday, November 20, 2017 8:45 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 970-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 970-2

Regards,

Erika Egede-Nissen
Media Relations Director, Caesarstone USA
818 314 4655
www.caesarstoneus.com

971

From: Erin Burke [mailto:erinburke777@yahoo.com]
Sent: Monday, November 20, 2017 1:02 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Najarian, Ara
Subject: Grayson Power Plant | Glendale

Dear Mr. Krause,

This letter is to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 971-1

First, I would ask for an independent study of clean energy alternatives to gas for meeting energy needs. Los Angeles is conducting this type of study presently via National Renewable Energy (NREL, under DoE), Glendale should do the same. 971-2

Secondly, operating a new plant will increase (GHG) greenhouse gas emissions which are a known cause of climate change increasing extreme heat days, drought and fires in our region. City Council signed a resolution to support the Paris Climate accord, this is in direct conflict with this agenda. 971-3

Thirdly, the effect on Glendale's air quality cannot be ignored. Our air already fails to meet federal clean air standards. Grayson will generate emissions that will increase several "criteria pollutants," that are known to increase the risk of asthma, cancers, heart disease, kidney disease, and other illnesses. This makes our children and elderly parents, especially at risk. 971-4

Two elementary schools, Franklin and Keppel are within walking distance of Grayson. My daughter is in a nearby home daycare, less that 2.5 miles away. She is 19 months old and this so this is especially personal to me. Her daycare has infants through 5 year olds and what i appreciate most is that they spend so much time playing outside, I do not want to have to leave Glendale to protect my child from poor air quality. We are already concerned about the quality of the air that our children breath as it is. We should do all we can to improve the air, not make it worse. 971-5

With renewable prices falling rapidly and many homeowners opting for solar this Grayson expansion is out of touch with the world we live in and the future we need to create. 971-6

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 971-7

Regards,

Erin E. Burke
Glendale Daycare Parent

Krause, Erik

From: ERINN HAYES <hayes4940@me.com>
Sent: Monday, November 20, 2017 7:26 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 972-1

No good justification has been given for why an expansion like this is needed. Also, the projected increase in greenhouse gas emissions is inconsistent with Glendale City Council's membership in the Mayors National Climate Action Agenda. 972-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 972-3

Regards,

Erinn Hayes, Highland Park CA

973

Krause, Erik

From: Flora Birdzell <flora.birdzell@gmail.com>
Sent: Monday, November 20, 2017 2:33 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Clean energy for Glendale!

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 973-1

I am raising three small children in this city and their health and that of all kids is of utmost importance to me. We must make good decisions for their future. If This project continues, I will seriously consider moving to escape the health consequences. What a shame for this city and our region. We need clean energy. 973-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 973-3

Regards,

Flora Birdzell
Glendale, CA

From: "Marian@friendsofgriffithpark.org" <Marian@friendsofgriffithpark.org>
Date: November 20, 2017 at 5:15:42 PM MST
To: <ekrause@glendaleca.gov>
Cc: Laura Friedman <Assemblymember.Friedman@assembly.ca.gov>, Seamus Garrity <Seamus.Garrity@asm.ca.gov>, <planzafame@glendaleca.gov>, <vgharpetian@glendaleca.gov>, <pdevine@glendaleca.gov>, <zsinanyan@glendaleca.gov>, <anajarian@glendaleca.gov>, <vagajanian@glendaleca.gov>
Subject: Grayson Power Plant DEIR Comments

Dear Mr. Krause,

Attached is the response from Friends of Griffith Park to the DEIR for the Grayson Power Plant.

Best regards,

Marian Dodge
President
Friends of Griffith Park

Friends of Griffith Park
P.O. Box 27573
Los Angeles, CA 90027-0573
friendsofgriffithpark.org

November 20, 2017

Erik Krause
Deputy Director of Planning
City of Glendale
633 E. Broadway Room 103
Glendale, CA 91206

Re: Grayson Power Plant

Dear Mr. Krause:

Friends of Griffith Park, a non-profit organization advocating for and supporting Griffith Park, has serious concerns regarding the proposal to rebuild and expand the aging Grayson Power Plant. The power plant's location directly across the Los Angeles River from Griffith Park means that the environmental impacts of the project will impact Griffith Park and its millions of visitors. 974-1

The proposed gas-powered project will increase the emission of greenhouse gasses. Meanwhile with SB 32, the entire State of California has committed to reducing greenhouse gasses to 40% below 1990 levels by 2030. How can Glendale meet this goal by *increasing* emissions? 974-2

The new plant will emit more pollutants and toxic emissions than the current plant. The plant is adjacent to residential areas and several schools. It is a well-established fact that pollutants have a greater impact on children than on adults because their bodies and brains are still developing. What impact will the increased pollutants have on the residents and school children? 974-3

Winds will carry pollutants across the river into Griffith Park and the Los Angeles Zoo. Millions of visitors come to Griffith Park every year. The zoo's primary clientele is small children, the most vulnerable of our population. Additionally the zoo is the home of numerous endangered species that the zoo is trying hard to preserve. What is the impact that the additional pollutants will have on hikers and children, on the native wildlife that calls Griffith Park home, and on the zoo animals? 974-4

Glendale has recently built a river walk along the Los Angeles River and has plans to construct a bridge so that residents can walk across the river to enter Griffith Park to enjoy hiking in the park. The idea is to encourage people to exercise more and be healthier while reducing the number of vehicle trips – a noble goal indeed. What will be the impact of the increased pollutants on the people who walk on the beautiful river walk and on the new bridge? 974-5

We were astounded that each alternative studied was found to have fewer pollutants and greenhouse gasses that the proposed project, and yet the proposed antiquated technology plan was found to be environmentally superior. What logic was used to arrive at that conclusion?! Has Glendale placed photovoltaic solar panels on every rooftop? That is a far more environmentally friendly and sustainable solution than the old fashioned proposed gas-fired plant. 974-6

Glendale is a forward-thinking city. Its citizens deserve a forward-thinking project which will be sustainable and met the state's renewable energy goals.

Sincerely,

Marian Dodge

Marian Dodge
President

cc: Assemblymember Laura Friedman

975

Krause, Erik

From: Franceli Izaguirre <franceliizaguirre@gmail.com>
Sent: Monday, November 20, 2017 2:31 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 975-1

As a resident of Glendale and mother to two young children, I am appalled that this would be allowed knowing the dangers it poses to the health and well-being of so many people. 975-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 975-3

Regards,

Franceli Izaguirre
Glendale, CA

976

Krause, Erik

From: Françoise Sawyer <francoise.sawyer@gmail.com>
Sent: Monday, November 20, 2017 3:53 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson repowering project

Dear Mr. Krause, I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 976-1

As a parent of a elementary school student at Franklin Magnet School, I'm deeply concerned by this irresponsable plan that will endanger the health of our children. 976-2

The fine print in your public report shows that the new plant will increase GHG emissions by 415,000 metric tons CO2 equivalent per year. 976-3
And that doesn't include the effects of methane emission leaks in the process of fracking, transporting and storing the gas.
At the same time, emissions of smog-producing criteria pollutants - like CO, NOx, SOx, and small particulate matter - are all increasing over current levels, 976-4
as are air toxics that cause cancer, kidney disease, cardiovascular disease, low birth weight, and other problems.

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. 976-5
This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR.

Regards,

Françoise Sawyer

From: Dan brotman [mailto:dhbrotman@gmail.com]
Sent: Monday, November 20, 2017 10:26 AM
To: Karamyan, Argishti
Subject: Fwd: Glendale Environmental Coalition comment letter on Grayson

Sent from my iPhone

Begin forwarded message:

> **From:** Daniel Brotman <dhbrotman@icloud.com>
> **Date:** November 20, 2017 at 1:20:44 AM PST
> **To:** Daniel Brotman <dhbrotman@gmail.com>
> **Subject: Glendale Environmental Coalition comment letter on Grayson**
>
> Dear Mr. Krause,
>
> Attachment available until Dec 20, 2017
>
> Please find attached the Glendale Environmental Coalition comment letter on the Grayson Draft EIR and associated exhibits.
>
> Best regards,
> Dan Brotman

November 20, 2017

Erik Krause, Interim Deputy Director
Glendale Community Development Department
633 East Broadway, Room 103
Glendale, CA 91206

Re: Grayson Repowering Draft Environmental Impact Report (DEIR)

Dear Mr. Krause:

I write on behalf of the Glendale Environmental Coalition (GEC), a grassroots group of over 200 motivated volunteers living or working in Glendale.

GEC is strongly opposed to the Grayson repowering project. We believe it is largely unneeded and would impose unacceptable financial, environmental, health, and safety risks. We believe there are clean energy alternatives to meet Glendale's power needs and that these alternatives have not been adequately evaluated. 977-1

This letter will explain the basis of the above claims, and we request that each be addressed directly and specifically. This letter will also include a number of questions that have not been clearly answered in the DEIR. In failing to disclose information crucial to a complete and adequate analysis of the project and its significant impacts, the DEIR fails to inform the public and decision-makers of the environmental consequences of the project, as required by the California Environmental Quality Act. 977-2

<u>The project significantly exceeds Glendale's power needs</u>

The project is described as a repowering, and the public has been led to believe that it is a simple replacement of old for new, cleaner-burning, technology. In fact, the project represents a significant expansion of both capacity and planned generation. 977-3

The DEIR claims a capacity increase of 43 MW. But this is misleading. The 43 MW is based on a comparison of nameplate capacity, yet the old units do not produce at nameplate and have not done so for many years. According to the most current Integrated Resource Plan (IRP) dated June 2015, the functional capacity of units 1, 2, 3, 4, 5, 8A, and 8B/C equals 185 MW. An honest comparison would be this 185 MW of functional capacity against 262 MW of net new capacity. On this basis, the capacity increase is in fact 77 MW or over 40%. This is not a repower, this is an expansion.

Not only is capacity increasing significantly, but two of the four new units are being permitted for nearly continuous operation. According to the DEIR, the combined cycle units are being permitted to run about 87% of the time, with the simple cycle units running about 20% of the time. In contrast, Mr. Zurn and his staff have previously stated that the older Grayson units are rarely used other than to burn Scholl Canyon landfill gas (LFG). This explains why total emissions are increasing so significantly despite the replacement of old units with new, cleaner-burning ones. We believe Glendale Water and Power (GWP) has misrepresented the nature of this project. 977-4

As for need, the 2015 IRP states, "Given current supply and peak load expectations, GWP currently maintains a sufficient capacity margin to support reliability and reserve requirements" (IRP at p. 16). At that time, GWP enjoyed a supply capacity of 423 MW (233 MW from existing Grayson, plus 190 MW of imported power) and peak demand of 320-325 MW. This suggests that GWP sees a buffer of 30% over peak demand as sufficient to support reliability and reserve requirements.

The proposed expansion would leave GWP with a net supply of about 490 MW (310 MW from the new units plus the existing unit 9, 12 MW from the Scholl Canyon biogas generation project, and 170 MW of imported capacity after adjusting for the divestment from San Juan coal). This would represent a supply-demand buffer of roughly 40%. 977-5

Over time, as power demand declines, that supply-demand buffer will widen. In fact, the IRP projects peak demand falling from 350 MW today to 300 MW by 2035 (in a meeting I had with Mr. Zurn and Councilwoman Devine on August 14, 2017, Mr. Zurn stated that this projected decline includes assumptions for economic/population growth in Glendale as well as expected take-up of electric vehicles). This suggests that within 15 years, GWP will enjoy a supply-demand buffer of roughly 64%. (We note that the loss of IPP coal could reduce supply by 38 MW if not replaced; in this event, the buffer remains at 50% by 2035.)

No supportable justification for this expansion has been given. The DEIR claims that federal and state regulations require GWP to maintain a supply buffer equal to the largest single contingency, but no details are provided. In the absence of information to support the DEIR's claim of the required supply buffer, the DEIR fails to provide information necessarily to informed decision-making, and its analysis is unsupported by substantial evidence. In order for this claim to be taken at face value, GWP must make public a full documentation of these regulations and its legal analysis of their implications for GWP's operations as a load-bearing entity. It should also show that these regulations are new since the 2015 IRP or, if not new, explain why there was no mention of them in the context of supply-demand representations in the 2015 IRP. 977-6

In this context, it should be noted that, while discussing the size of the proposed upgrade at a presentation to the City Council on June 2, 2015, Gary Vicinus, a consultant from Pace Global, stated that "you only need about 200 [MW] to actually meet your load and requirements, the others would be sold down." We request a detailed explanation for what has changed since the time of that presentation that justifies the 262 MW project currently being proposed, especially since GWP management stated at the October 16, 2017, hearing that the current proposal does not assume the sale of power. 977-7

<u>The project would impose unacceptable financial risks on Glendale ratepayers</u>

Although a detailed financial analysis has not been made publicly available, we believe GWP has failed to take into account several serious risks to the economic viability of the project. Among these are potential changes in state legislation which would restrict GWP's ability to burn fossil fuels, challenges associated with market sales of excess power, and the potential for significant increases in the price of carbon credits under the cap and trade market system. 977-8

In terms of legislation, several bills are being considered that would limit GWP's ability to make full use of the new units. Most important is SB 100, sponsored by Sen. De Leon, which would increase the renewable portfolio standard (RPS) to 60% by 2030 and set a new goal of 100% zero-carbon electricity by 2045. This bill, which has already passed out of the Senate, is expected to be taken up in 2018 and has a high likelihood of becoming law. In this event, GWP would be forced to mothball the new units by 2045, giving them at best 23-24 years of operational life. In the above referenced August 14, 2017 conversation with Mr. Zurn, I was told that the NPV analysis supporting the 250D project option (on which the current proposal is based) assumed a 30-year economic life. If this were reduced to 23-24 years, the project would no longer be as financially attractive relative to clean energy alternatives. The real risk is that Glendale ratepayers will end up paying for power they cannot use, and paying again for the costs of replacement renewable power. And this is likely to occur well before 2045 as RPS requirements tighten. 977-8

The financial justification for the proposed expansion clearly depends on the sale of power outside Glendale. While GWP management currently denies this is the case, the 2015 IRP is explicit in stating that the proposal "relies heavily on market sales" (IRP at p. 52), and both GWP officials and Pace Global consultants recommended in oral testimony at that time that Glendale enter into purchase power agreements (PPAs) with third-party buyers. The concern for Glendale ratepayers is that California is currently facing a glut of gas-fired generation (see "Californians are paying billions for power they don't need," LA Times, February 5, 2017, attached as Exhibit A) which raises the possibility that the City will be unable to find a long-term partner and/or be forced to sell power below cost on the market. California-based Investor Owned Utilities (IOUs) are increasingly reluctant to enter into long-term PPAs for fossil fuel power in any case. In the end, the risks are too great that sales will fall short, leaving the full burden of capital costs on ratepayers. 977-9

In this context, we would like to know whether GWP has had any informal discussions or entered into any formal negotiations with potential PPA counterparties, and what the outcome of those discussions or negotiations has been. GWP management stated in 2015 that several buyers expressed interest; what was the follow-up to those overtures? 977-10

One important cost component of fossil fuel generation is the price of carbon. Ever since the passage of AB 32, California has been operating under a cap and trade program which requires polluting entities to acquire carbon credits. For most of the period since the program was established, carbon credits have been trading at or below $15 per metric ton of CO_2e ($MTCO_2e$). However, prices are expected to rise sharply once the current oversupply of credits is drawn down around 2023-24, as discussed below. 977-11

For the purposes of its financial modeling, GWP has assumed an initial carbon cost of $15 per $MTCO_2e$, rising to approximately $30 per $MTCO_2e$ by 2030. GWP's assumptions are not supported by the most current market forecasts. In fact, a recent supply and demand analysis and 2030 price forecast by CaliforniaCarbon.info (see "Analyst Note," October 2017, attached as Exhibit B) shows the price of carbon credits rising to over $90 $MTCO_2e$ by 2030 in its base case scenario. Given that the Grayson repowering will increase annual greenhouse gas (GHG) emissions by over 415,000 $MTCO_2e$ according to the DEIR, the cost differential just over the

period 2020 to 2035 is conservatively estimated at $200 million. GWP will argue that they have banked credits and are allocated free credits annually by the Air Resources Board. This may be true, but the credits have an opportunity cost, as they may be sold if not used, with proceeds accruing to the benefit of ratepayers. Consequently, this additional $200 million must be added to the project cost. 977-11

The projected increase in greenhouse gas emissions is inconsistent with Glendale City Council's membership in the Mayors National Climate Action Agenda

The DEIR estimates that GHG emissions will increase by over 415,000 $MTCO_2e$ per year. This compares to a baseline of just under 61,000 $MTCO_2e$ from the units to be retired, or an astonishing 680% increase. According to the US Environmental Protection Agency's "Greenhouse Gas Equivalencies Calculator," this is equivalent to adding 88,865 cars to Glendale roads (attached as Exhibit C). 977-12

As significant as this appears, it only includes GHG emissions from the combustion of natural gas for power generation. It does not include the very significant releases of methane—a short-lived but highly potent climate forcing gas—that occur in the extraction, transportation, storage, and handling of natural gas. According to a March 1, 2017, post by the Environmental Defense Fund (attached at Exhibit D), which is based on a January 2017 CARB and CPUC Joint Staff Report (attached as Exhibit E), California gas utilities lost 6.6 billion cubic feet of methane in 2015, more than was lost in the Aliso Canyon disaster. As leak detection and measurement improves, we are learning that natural gas, rather than being a clean bridge away from coal, is a power source that may have equally significant impacts on global warming. The DEIR's failure to analyze GHG emissions from methane releases renders its GHG analysis inadequate and insufficient to inform the public and decision-makers of the true impacts of the Grayson repowering project.

How is it possible that Glendale would pass a resolution joining the Mayors National Climate Action Agenda and then just a few months later propose a project that would increase known GHG emissions by 6.8 times and enhance the risk of additional unmeasured and unmitigated methane leakages? How can GWP show so little regard for the welfare of Glendale residents and future generations here and across the globe to propose such a substantial increase in fossil fuel generation at a time when evidence shows climate change impacts are clear and present and becoming more alarming by the day?

We also ask that GWP explain the contradiction between the emissions figures above and its statement at the Public Scoping Meeting on January 12, 2017, that "The repowered units are more energy efficient, **create less emissions** [emphasis added], and increase reliability of the power grid." (see presentation by Michael Weber, p. 11, attached as Exhibit F). This statement appears to be an unambiguous misrepresentation of the nature of the project.

The project will increase emissions of criteria pollutants and air toxics and harm the health of residents in proximity to the plant 977-13

Not only does the project threaten long-term climate stability, but it will also negatively affect short-term and long-term health outcomes for thousands of people living near the plant and throughout Glendale and neighboring Burbank and Northeast Los Angeles.

977-13

As spelled out in the DEIR, emissions of all criteria pollutants—including VOCs, CO, NO_x, SO_x, PM_{10}, and $PM_{2.5}$—will increase over current levels. Some of these emissions do not cross SCAQMD's significance threshold, but some—such as VOCs and NO_x—do. Even if simple adoption of SCAQMD's thresholds—something the DEIR did without reasoned explanation—were appropriate, the impacts are significant.

GWP's plan to mitigate these emissions increases involve acquiring offsets from SCAQMD or other polluters in the air basin. This raises two issues.

First, offsets do nothing to mitigate the effect of increased emissions of criteria pollutants on the *local* air quality. Will GWP commit to children at Mark Keppel and Franklin Elementary and the Disney Children's Center that the air they breathe at school and on the playground will not be worse after the repowering than it is today? Will they make the same commitment to elderly residents in Pelanconi Estates? If they cannot, the mitigation included in the DEIR is irrelevant to those vulnerable communities. GWP should evaluate the impact of increased emissions of particulates on health, including the incidence of kidney disease (see "Air Pollution Tied to Kidney Disease," New York Times, September 21, 2017, attached as Exhibit G) and dementia (see "The Surprising Link Between Air Pollution and Alzheimer's Disease," LA Times, January 31, 2017, attached as Exhibit H). Its decisions today may well increase the incidence of these diseases, as well as of cardiovascular disease, asthma, and low birth weight, among others. Given the potential for l severe health effects, the DEIR failed to adequately analyze a significant environmental impact of this project, notwithstanding the regional and localized significance thresholds adopted from SCAQMD. And it fails to adequately mitigate these effects to the area population, including sensitive receptors.

977-14

Second, we understand the SCAQMD air basin is out of compliance on PM_{10} emissions and that no remaining PM_{10} emissions credits are available for purchase. The proposed plant will need to acquire credits at a rate of 1.2 to 1 in order to obtain an air permit from SCAQMD. And such an air permit is required prior to the start of construction of the proposed project. Yet, in the DEIR, GWP states that emissions offsets "are envisioned to be purchased by the City as Emission Reduction Credits (ERCs) in the open market, prior to the start of construction." We would like to see GWP present the certificates for all the necessary offsets for this plant prior to any additional funds being spent, since the project will not be able to be constructed without these currently unavailable offsets. In the absence of further investigation ensuring the availability of these credits, the DEIR's discussion represents impermissibly deferred analysis.

977-15

On a related point, the DEIR states that the PM_{10} emissions would be limited to 3.3 metric pounds per hour for the simple cycle units and 2.2 metric pounds per hour for the combined cycle units. These emissions rates are high for California, and other simple cycle plants have air permits that limit PM_{10} emissions to 2.0-2.5 metric pounds per hour. At a minimum, the approved emissions rates for this project should meet the approved emissions rates of other

plants that have been permitted in the state. The DEIR is inadequate in failing to discuss these emissions rates. 977-15

The DEIR also shows that the upgrade and expansion of Grayson will increase emissions of air toxics over current levels. Air toxics are extremely dangerous substances for which, unlike criteria pollutants, there are no known safe levels according to the EPA. 977-16

It is unclear from the DEIR what population density was used for the cancer burden and pollution risks. It appears as if this analysis in the DEIR uses the population density of Los Angeles County, which is significantly lower than the population density of Glendale. (according to the 2010 US Census, Glendale had 6,269 people per sq. mi., whereas Los Angeles County overall had 2,344 people per sq. mi.). Additionally, the worker population in the area of the plant must be included in the estimates of cancer burden and other pollution risks. The significant daytime worker density around the plant, especially considering the nearby Disney Creative Campus, was not included in the DEIR. This industrial zone has become a densely populated area during the workday, and the EIR process requires the use of real densities for the pollution risk calculations. The DEIR's failure to accurately account for local population densities, including worker population, renders it inadequate as a tool in informed decision-making. 977-17

Apart from the harmful effects of increased air pollution from plant operations, the DEIR describes the potential risk of asbestos dispersion as a result of site demolition. It also describes the potential increase in VOCs, PMs and other air pollutants which will occur as a result of the removal of several feet of soil under the current structure. We are deeply concerned about both of these risks, especially because it appears that GWP either does not fully understand or is underestimating the extent of the demolition and clean up issues. 977-18

The proposed project description in the DEIR cites an 8-foot depth of disturbance. However, as a June 30, 1940 article about the plant makes clear (see "Plant Built in Open," attached at Exhibit I) the plant is sited on top of a 22-foot-deep basement. It is unclear how GWP intends to handle the large quantities of hazardous materials—including asbestos laden pipes, oil containers and other unknown materials—that are likely sitting beneath the proposed 8-foot disturbance layer. Because the DEIR has not detailed the extent of the problem or GWP's intentions in addressing it, the public is unable to determine exactly how long the demolition portion of the project will actually take, how much it will cost, and what environmental risks and community disruption (be it noise or traffic) will ultimately be involved.

Especially with consideration that there are vulnerable children at nearby schools and daycare centers, a full analysis of potentially toxic substances in the extensive basement area is crucial to a complete and accurate understanding of the project's environmental impacts. These impacts must be fully analyzed and set forth in a recirculated DEIR that complies with CEQA's mandate that environmental analysis occur *before* the project is approved.

<u>The project will subject Glendale to unacceptable risks in the event of a major earthquake</u> 977-19

One rationale for the Grayson project is the desire to maintain a level of energy security should an unforeseen event—such as a major earthquake—cause long-distance transmission lines to fail. Unfortunately, this rationale is undercut by the fact that the plant would be sited in a known earthquake liquefaction zone. It is highly likely that in the event of a magnitude 7.0 or larger quake, ground movement would be enough to sever gas pipes, leading at worst to gas leaks, explosions, and fires, and at best to incapacitating the major source of power Glendale hopes to rely on in just such a situation. 977-19

In their testimony at the hearing on October 16, 2017, consultants from Stantec downplayed this risk by explaining how Grayson successfully withstood the Sylmar earthquake—a magnitude 6.6 quake that lasted for 12 seconds. While this is certainly good news, we cannot assume Grayson will react to future earthquakes in the same manner. Even with an earthquake of similar or lesser intensity, the different stresses of each individual event create different effects (as was the case in the recent Mexico City earthquake, in which many buildings collapsed that had withstood the stronger 1985 earthquake; see "Mexico City residents whose buildings survived the 1985 quake thought they'd be safe in the next big one. They were wrong," LA Times, September 20, 2017, attached as Exhibit J). According to the renowned seismologist Dr. Lucy Jones, California residents must be prepared for an earthquake of up to 8.2 magnitude on the San Andreas fault—which it should be noted would be 250 times stronger than the Sylmar earthquake (see "California could be hit by an 8.2 mega-earthquake, and it would be catastrophic," LA Times, September 19, 2017, attached as Exhibit K). Has GWP done engineering analysis to determine how Grayson would withstand an earthquake of this size? If so, the DEIR does not present the results or discuss the impacts from such an earthquake. Can they honestly defend the position that centralized generation in an area subject to liquefaction risk is the best solution to energy resilience and reliability for Glendale? In our view, this type of risk is best mitigated with a distributed solution based on a combination of solar, battery storage, and microgrid infrastructure and not one built around a single point of failure.

<u>Clean energy and demand management alternatives have not been adequately studied</u>

The Grayson DEIR considers, but rejects, both a battery storage system alternative and a solar alternative. Individually, each system may have its flaws, since an energy storage project requires energy to be produced by another source to charge the battery, and the solar project is intermittent, only operating when the sun is shining. However, the combination of a solar and energy storage system would solve the problems inherent in the individual alternatives. The solar plant does not necessarily need to be a large plant with large acreage. If appropriate incentives are given to homeowners, and to commercial and industrial users, these solar projects can be distributed across the roofs and parking lots of the city. Any solar power not used by the customer can be sent to the grid to charge the batteries. 977-20

Unfortunately, GWP and its consultants neither studied an integrated solution like this, nor did it measure the potential for solar generation on city-owned and -controlled facilities. At the October 16, 2017, hearing, the Stantec consultant admitted as much when answering a question posed by Commissioner Hale on the amount of solar potential where Glendale has site control (answer "I do not believe that we looked at how much renewable power could be

generated on sites within the city that the city has control over."). If GWP has not evaluated the potential for solar from city-controlled space, let alone what might be possible on residential and commercial rooftops with the right incentives, how can it rule out the potential for solar plus storage—in combination with existing gas from Unit 9 and gas from Burbank—to meet its maximum load requirements even in the event of a loss of the single largest contingency? The full potential for solar, and the combined alternative of solar plus storage, must be fully explored before any proposed plant is approved. The DEIR's failure to consider these alternatives renders its alternatives analysis inadequate. 977-20

Moreover, the DEIR misapprehends the requirement of identifying an environmentally superior alternative. The DEIR identifies at least two alternatives as having fewer environmental impacts than the proposed project, but rejects them for reasons other than their environmental impacts, and concludes instead that the project itself is the environmentally superior alternative. But it is illogical to conclude a project with greater impacts is environmentally superior to alternatives with fewer impacts. The discussion fails to provide information needed for informed decision-making.

Throughout the IRP and EIR process, GWP's approach has been to build to estimated peak load and then add additional capacity to cover a range of contingencies. This backward-looking approach shortchanges a full assessment of how to minimize demand spikes in the first place. If maximum demand (currently estimated at 350 MW) occurs only on a few days out of the year and even then only during certain times of the day, the first effort should be to introduce methodologies to reduce demand through energy efficiency, but just as importantly to shift demand temporally and compress the gap between average and peak demand. Many methodologies are now available to do this, from simple time of use (TOU) pricing systems, which GWP has not fully exploited, to more sophisticated technologies including systems in which ratepayers allow the utility to modulate HVAC systems in real time to smooth demand. More such technologies are being introduced every year. Before building a plant based on today's maximum load, GWP must first demonstrate it has studied every available demand response technology and show why that technology would not be effective in reducing load-serving capacity requirements. 977-21

Grayson's aging infrastructure provides a unique opportunity for GWP to chart a new path in power delivery to the city it has so ably serviced since the 1940s. By taking seriously the clean energy, storage, demand management, and energy efficiency technologies available today, and those expected to emerge over the next 5-10 years, GWP could establish itself as a forward-looking utility. It could contribute to cleaning the air around the plant and throughout the air basin, to creating greater resilience through distributed generation, and to generating local jobs through an active rollout of solar installations. We call on GWP to shelve the current repowering proposal and go back to the drawing board with a study of how renewables, battery storage, energy efficiency, and demand management, in combination with other sources of power available to Glendale today, can meet the City's needs today and into the future. Such a study should be carried out by an organization such as NREL or E3 which has strong clean energy credentials and not a group such as Stantec or Pace Global whose expertise is based in fossil fuel technologies. 977-22

Environmental justice impact have not been evaluated

The DEIR inappropriately excluded analysis of the environmental justice impacts of the project and is therefore incomplete.

The document states that "Glendale is not considered an environmental justice community and the Project would therefore not substantially increase project air emissions that disproportionately impact low-income or minority communities in proximity to the project site." This determination was derived by comparing poverty and ethnic makeup of the City of Glendale in its entirety against Los Angeles County. But this is a flawed analysis. 977-23

A proper analysis would focus on the population living adjacent to Grayson, for instance, within one square mile of the plant, regardless of whether that area falls within the city limits of Glendale. Much of this population already faces compromised environmental and social conditions, as evidenced by the fact that these areas receive the worst impact scores per the CalEnviroScreen tool (https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30, attached as Exhibit L) and some of the worst scores on the Health Disadvantaged Index (http://phasocal.maps.arcgis.com/apps/Viewer/index.html?appid=e1215eae472a4c458c5e9157d6b8ec8e, see HDI score for census tract 1316.01 attached as Exhibit M). The area around the plant also has a "disadvantaged community" designation from CalEPA for the purposes of SB 535 (map attached as Appendix N).

These neighborhoods will experience the most direct impact from increases in criteria air pollutants and air toxics both during construction and during plant operations. The income levels and ethnic mix of this population should be compared against that of a baseline population—either Glendale as a whole or Los Angeles County—in order to determine if an environmental justice issue exists.

Sincerely,

Daniel Brotman
Co-founder, Glendale Environmental Coalition

cc: Glendale City Council Members
Glendale Water and Power Commissioners
Senator Anthony Portantino
Assemblymember Laura Friedman

Exhibit A: “Californians are paying billions for power they don’t need,” LA Times, February 5, 2017

Exhibit B: CaliforniaCarbon.info, “Analyst Note,” October 2017

Exhibit C: US Environmental Protection Agency “Greenhouse Gas Equivalencies Calculator” results for 415,000 metric tons of carbon dioxide equivalent

Exhibit D: Environmental Defense Fund blog post, March 1, 2017

Exhibit E: CARB and CPUC Joint Staff Report, “Analysis of the Utilities’ June 17, 2016, Methane Leak and Emissions Report Required by SB 1371,” January 2017

Exhibit F: Presentation by Michael Weber, “Environmental Impact Report Public Scoping Meeting for Grayson Repowering Project,” January 12, 2017

Exhibit G: “Air Pollution Tied to Kidney Disease,” New York Times, September 21, 2017

Exhibit H: “The Surprising Link Between Air Pollution and Alzheimer’s Disease,” LA Times, January 31, 2017

Exhibit I: “Power Plant Built in Open,” Los Angeles Times, June 30, 1940

Exhibit J: “Mexico City residents whose buildings survived the 1985 quake thought they’d be safe in the next big one. They were wrong,” LA Times, September 20, 2017

Exhibit K: “California could be hit by an 8.2 mega-earthquake, and it would be catastrophic,” LA Times, September 19, 2017

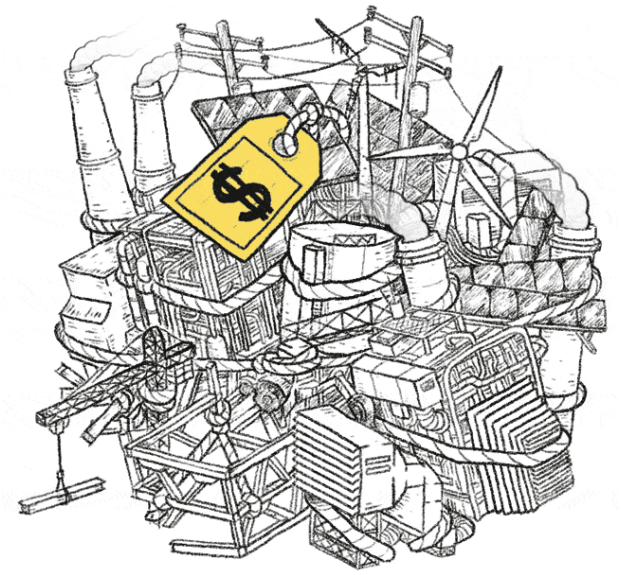
Exhibit L: CalEnviroScreen tool (https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30) results for area surrounding Grayson Power Plant

Exhibit M: Health Disadvantaged Index http://phasocal.maps.arcgis.com/apps/Viewer/index.html?appid=e1215eae472a4c458c5e9157d6b8ec8e, score for census tract 1316.01

Exhibit N: CalEPA SB 535 Disadvantaged Communities map of area around Grayson Power Plant

Los Angeles Times (HTTP://WWW.LATIMES.COM/)

Californians are paying billions for power they don't need



We're using less electricity. Some power plants have even shut down. So why do state officials keep approving new ones?

By IVAN PENN (HTTP://WWW.LATIMES.COM/LA-BIO-IVAN-PENN-STAFF.HTML) and RYAN MENEZES (HTTP://WWW.LATIMES.COM/LA-BIO-RYAN-MENEZES-STAFF.HTML) | Reporting from Yuba City, Calif.

FEB. 5, 2017

Read the story

View the interactive graphic (/projects/la-fi-electricity-capacity-graphic/)

The bucolic orchards of Sutter County north of Sacramento had never seen anything like it: a visiting governor and a media swarm — all to christen the first major natural gas power plant in California in more than a decade.

At its 2001 launch, the Sutter Energy Center was hailed as the nation's cleanest power plant. It generated electricity while using less water and natural gas than older designs.

A year ago, however, the $300-million plant closed indefinitely, just 15 years into an expected 30- to 40-year lifespan. The power it produces is no longer needed — in large part because state regulators approved the construction of a plant just 40 miles away in Colusa that opened in 2010.

"We are building more power plants in California than ever before. Our goal is to make California energy self–sufficient." - Gov. Gray Davis at the opening of Sutter Energy Center in 2001. (Carolyn Cole / Los Angeles Times)

Sutter Energy Center has been offline since 2016, after just 15 years of an expected 30- to 40-year lifespan. (David Butow / For The Times)

Two other large and efficient power plants in California also are facing closure decades ahead of schedule. Like Sutter, there is little need for their electricity.

California has a big — and growing — glut of power, an investigation by the Los Angeles Times has found. The state's power plants are on track to be able to produce at least 21% more electricity than it needs by 2020, based on official estimates. And that doesn't even count the soaring production of electricity by rooftop solar panels that has added to the surplus.

To cover the expense of new plants whose power isn't needed — Colusa, for example, has operated far below capacity since opening — Californians are paying a higher premium to switch on lights or turn on electric stoves. In recent years, the gap between what Californians pay versus the rest of the country has nearly doubled to about 50%.

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This translates into a staggering bill. Although California uses 2.6% less electricity annually from the power grid now than in 2008, residential and business customers together pay $6.8 billion more for power than they did then. The added

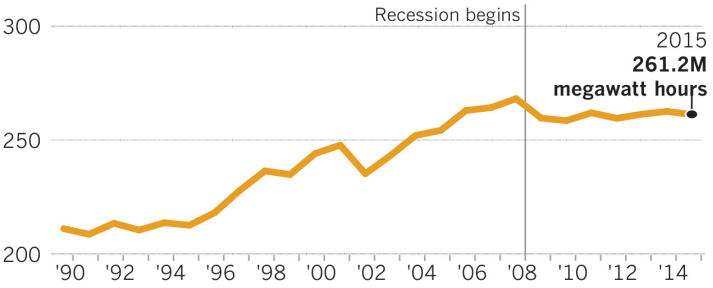
cost to customers will total many billions of dollars over the next two decades, because regulators have approved higher rates for years to come so utilities can recoup the expense of building and maintaining the new plants, transmission lines and related equipment, even if their power isn't needed.

How this came about is a tale of what critics call misguided and inept decision-making by state utility regulators, who have ignored repeated warnings going back a decade about a looming power glut.

"In California, we're blinding ourselves to the facts," said Loretta Lynch, a former president of the California Public Utilities Commission, who along with consumer advocacy groups has fought to stop building plants. "We're awash in power at a premium price."

California regulators have for years allowed power companies to go on a building spree, vastly expanding the potential electricity supply in the state. Indeed, even as electricity demand has fallen since 2008, California's new plants have boosted its capacity enough to power all of the homes in a city the size of Los Angeles — six times over. Additional plants approved by regulators will begin producing more electricity in the next few years.

California's electricity usage peaked in 2008, just as a recession forced customers to scale back.



Source: Energy Information Administration
Graphics reporting by Ryan Menezes
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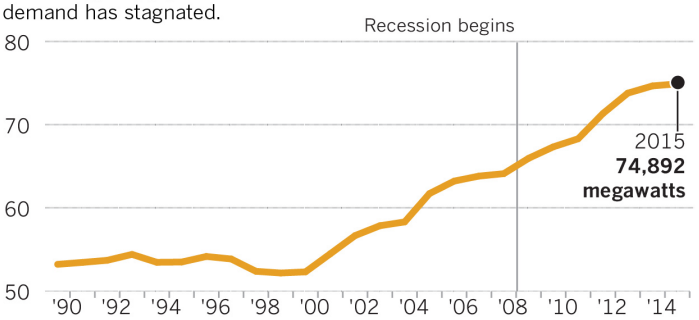
The **energy supply** in California has continued to rise, even as demand has stagnated.



Source: Energy Information Administration
Graphics reporting by Ryan Menezes
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The missteps of regulators have been compounded by the self-interest of California utilities, Lynch and other critics contend. Utilities are typically guaranteed a rate of return of about 10.5% for the cost of each new plant regardless of need. This creates a major incentive to keep construction

going: Utilities can make more money building new plants than by buying and reselling readily available electricity from existing plants run by competitors.

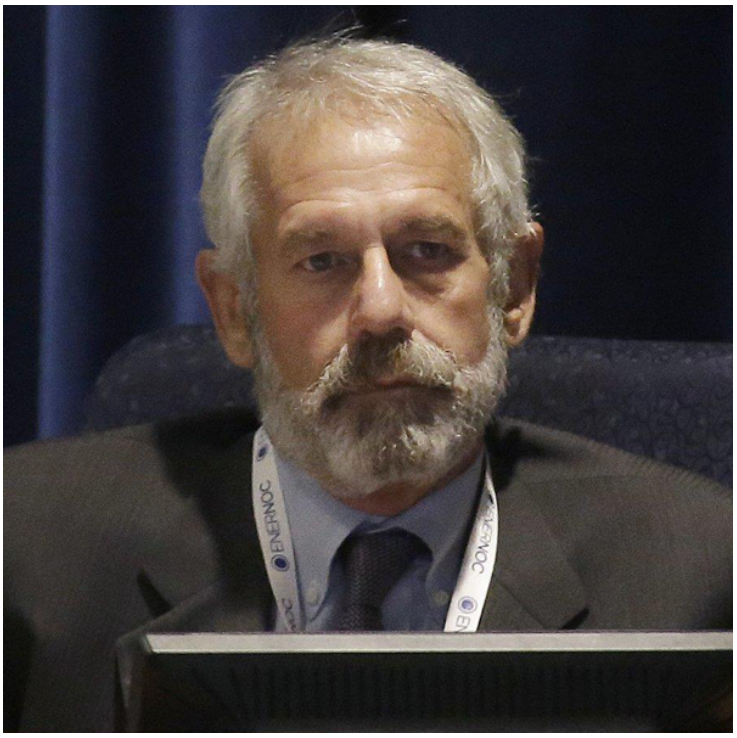
Regulators acknowledge the state has too much power but say they are being prudent. The investment, they maintain, is needed in case of an emergency — like a power plant going down unexpectedly, a heat wave blanketing the region or a wildfire taking down part of the transmission network.

"We overbuilt the system because that was the way we provided that degree of reliability," explained Michael Picker, president of the California Public Utilities Commission. "Redundancy is important to reliability."

Some of the excess capacity, he noted, is in preparation for the retirement of older, inefficient power plants over the next several years. The state is building many new plants to try to meet California environmental standards requiring 50% clean energy by 2030, he said.

In addition, he said, some municipalities — such as the Los Angeles Department of Water and Power — want to maintain their own separate systems, which leads to inefficiencies and redundancies. "These are all issues that people are willing to pay for," Picker said.

Critics agree that some excess capacity is needed. And, in fact, state regulations require a 15% cushion. California surpasses that mark and is on pace to exceed it by 6 percentage points in the next three years, according to the Western Electricity Coordinating Council, which tracks capacity and reliability. In the past, the group has estimated the surplus would be even higher.



Michael Picker, current president of California's Public Utilities Commission, said the state's excess power supply is a strategic decision to ensure reliability. Loretta Lynch, who held the same position from 2002 to 2005, has been a critic of overbuilding since she chaired the regulatory agency. (Associated Press)

Even the 15% goal is "pretty rich," said Robert McCullough of Oregon-based McCullough Research, who has studied California's excess electric capacity for both utilities and regulators. "Traditionally, 10% is just fine. Below 7% is white knuckle. We are a long way from white-knuckle time" in California.

Contrary to Picker's assertion, critics say, customers aren't aware that too much capacity means higher rates. "The winners are the energy companies," Lynch said. "The losers are businesses and families."

The over-abundance of electricity can be traced to poorly designed deregulation of the industry, which set the stage for blackouts during the energy crisis of 2000-2001.

Lawmakers opened the state's power business to competition in 1998, so individual utilities would no longer enjoy a monopoly on producing and selling electricity. The goal was to keep prices lower while ensuring

adequate supply. Utilities and their customers were allowed to buy electricity from new, unregulated operators called independent power producers.

The law created a new exchange where electricity could be bought and sold, like other commodities such as oil or wheat.

Everyone would benefit. Or so the thinking went.

In reality, instead of lowering electricity costs and spurring innovation, market manipulation by Enron Corp. and other energy traders helped send electricity prices soaring.

That put utilities in a bind, because they had sold virtually all their natural gas plants. No longer able to produce as much of their own electricity, they ran up huge debts buying power that customers needed. Blackouts spread across the state.

State leaders, regulators and the utilities vowed never to be in that position again, prompting an all-out push to build more plants, both utility-owned and independent.

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"They were not going to allow another energy crisis due to a lack of generation," said Alex Makler, a senior vice president of Calpine, the independent power producer that owns the Sutter Energy plant not far from Sacramento.

But the landscape was starting to change. By the time new plants began generating electricity, usage had begun a decline, in part because of the economic slowdown caused by the recession but also because of greater energy efficiency.

The state went from having too little to having way too much power.

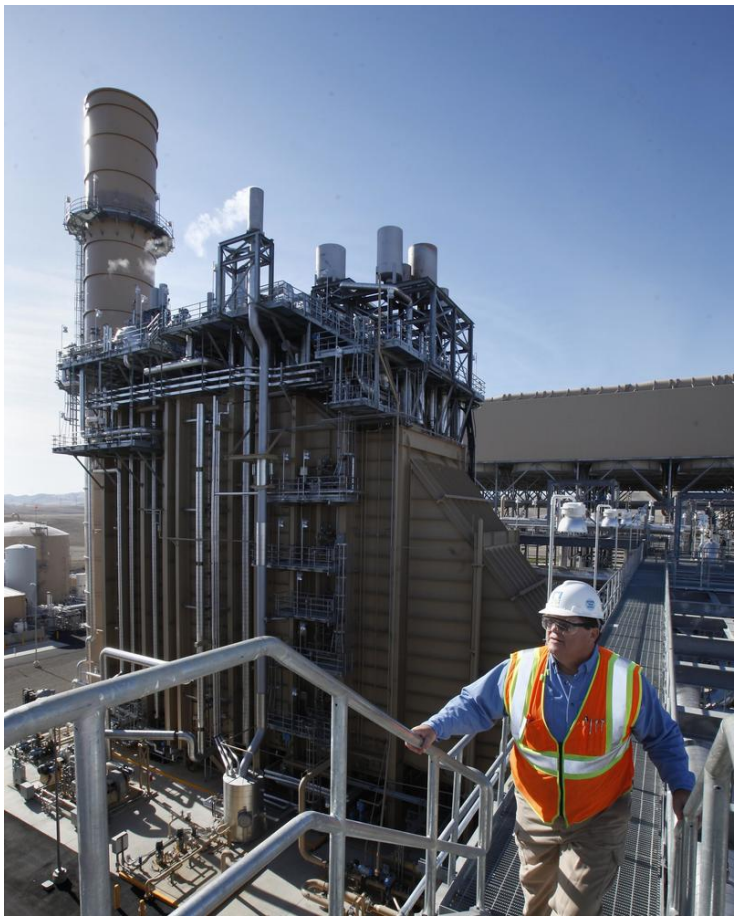
"California has this tradition of astonishingly bad decisions," said McCullough, the energy consultant. "They build and charge the ratepayers. There's nothing dishonest about it. There's nothing complicated. It's just bad planning."

> California has this tradition of astonishingly bad decisions.
>
> — Robert McCullough, energy consultant

The saga of two plants — Sutter Energy and Colusa — helps explain in a microcosm how California came to have too much energy, and is paying a high price for it.

Sutter was built in 2001 by Houston-based Calpine, which owns 81 power plants in 18 states.

Sutter Energy Center, now closed, made money only if Calpine Corp. found customers for the plant's power. Other large, natural gas plants in the state also face early closures. (David Butow / For The Times)



Colusa Generating Station opened in 2010. Pacific Gas & Electric will charge ratepayers more than $700 million over the plant's lifespan, to cover its operating costs and the profit guaranteed to public utility companies. (Rich Pedroncelli / AP)

Independents like Calpine don't have a captive audience of residential customers like regulated utilities do. Instead, they sell their electricity under contract or into the electricity market, and make money only if they can find customers for their power.

Sutter had the capacity to produce enough electricity to power roughly 400,000 homes. Calpine operated Sutter at an average of 50% of capacity in its early years — enough to make a profit.

But then Pacific Gas & Electric Co., a regulated, investor-owned utility, came along with a proposal to build Colusa.

It was not long after a statewide heat wave, and PG&E argued in its 2007 request seeking PUC approval that it needed the ability to generate more power. Colusa — a plant almost identical in size and technology to Sutter —

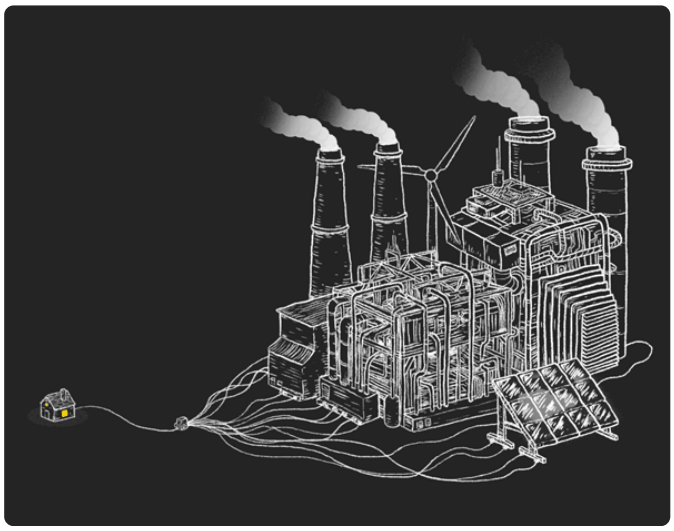
was the only large-scale project that could be finished quickly, PG&E said.

More than a half-dozen opponents, including representatives of independent power plants, a municipal utilities group and consumer advocates filed objections questioning the utility company. Wasn't there a more economical alternative? Did California need the plant at all?

They expressed concern that Colusa could be very expensive long-term for customers if it turned out that its power wasn't needed.

That's because public utilities such as PG&E operate on a different model.

If electricity sales don't cover the operating and construction costs of an independent power plant, it can't continue to run for long. And if the independent plant closes, the owner — and not ratepayers — bears the burden of the cost.



(/projects/la-fi-electricity-capacity-graphic/) (/projects/la-fi-electricity-capacity-graphic/) (/projects/la-fi-electricity-capacity-graphic/) California's energy supply: From blackouts to glut (/projects/la-fi-electricity-capacity-graphic/)

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In contrast, publicly regulated utilities such as PG&E operate under more accommodating rules. Most of their revenue comes from electric rates approved by regulators that are set at a level to guarantee the utility recovers all costs for operating the electric system as well as the cost of building or buying a power plant — plus their guaranteed profit.

Protesters argued Colusa was unnecessary. The state's excess production capacity by 2010, the year Colusa was slated to come online, was projected to be almost 25% — 10 percentage points higher than state regulatory requirements.

The looming oversupply, they asserted, meant that consumers would get stuck with much of the bill for Colusa no matter how little customers needed its electricity.

And the bill would be steep. Colusa would cost PG&E $673 million to build. To be paid off, the plant will have to operate until 2040. Over its lifetime, regulators calculated that PG&E will be allowed to charge more than $700 million to its customers to cover not just the construction cost but its operating costs and its profit.

Pacific Gas & Electric's Colusa Generating Station has operated at well below its generating capacity — just 47% in its first five years. (Rich Pedroncelli / AP)

The urgent push by PG&E "seems unwarranted and inappropriate, and potentially costly to ratepayers," wrote Daniel Douglass, a lawyer for industry groups that represent independent power producers.

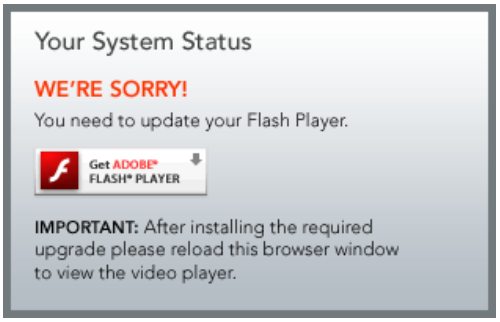
The California Municipal Utilities Assn. — whose members buy power from public utilities and then distribute that power to their customers — also complained in a filing that PG&E's application appeared to avoid the issue of how Colusa's cost would be shared if it ultimately sat idle. PG&E's "application is confusing and contradicting as to whether or not PG&E

proposes to have the issue of stranded cost recovery addressed," wrote Scott Blaising, a lawyer representing the association. ("Stranded cost" is industry jargon for investment in an unneeded plant.)

The arguments over Colusa echoed warnings that had been made for years by Lynch, the former PUC commissioner.

A pro-consumer lawyer appointed PUC president in 2000 by Gov. Gray Davis, Lynch consistently argued as early as 2003 against building more power plants.

"I was like, 'What the hell are we doing?' " recalled Lynch.



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She often butted heads with other commissioners and utilities who pushed for more plants and more reserves. Midway though her term, the governor replaced her as president — with a former utility company executive.

One key battle was fought over how much reserve capacity was needed to guard against blackouts. Lynch sought to limit excess capacity to 9% of the state's electricity needs. But in January 2004, over her objections, the PUC approved a gradual increase to 15% by 2008.

"We've created an extraordinarily complex system that gives you a carrot at every turn," Lynch said. "I'm a harsh critic because this is intentionally complex to make money on the ratepayer's back."

With Lynch no longer on the PUC, the commissioners voted 5-0 in June 2008 to let PG&E build Colusa. The rationale: The plant was needed, notwithstanding arguments that there was a surplus of electricity being produced in the market.

PG&E began churning out power at Colusa in 2010. For the nearby Sutter plant, that marked the beginning of the end as its electricity sales plummeted.

In the years that followed, Sutter's production slumped to about a quarter of its capacity, or just half the rate it had operated previously.

Calpine, Sutter's owner, tried to drum up new business for the troubled plant, reaching out to shareholder-owned utilities such as PG&E and other potential buyers. Calpine even proposed spending $100 million to increase plant efficiency and output, according to a letter the company sent to the PUC in February 2012.

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PG&E rejected the offer, Calpine said, "notwithstanding that Sutter may have been able to provide a lower cost."

Asked for comment, PG&E said, "PG&E is dedicated to meeting the state's clean energy goals in cost-effective ways for our customers. We use competitive bidding and negotiations to keep the cost and risk for our customers as low as possible." It declined to comment further about its decision to build Colusa or on its discussions with Calpine.

Without new contracts and with energy use overall on the decline, Calpine had little choice but to close Sutter.

During a 2012 hearing about Sutter's distress, one PUC commissioner, Mike Florio, acknowledged that the plant's troubles were "just the tip of the proverbial iceberg." He added, "Put simply, for the foreseeable future, we have more power plants than we need."

Colusa, meanwhile, has operated at well below its generating capacity — just 47% in its first five years — much as its critics cautioned when PG&E sought approval to build it.

Sutter isn't alone. Other natural gas plants once heralded as the saviors of California's energy troubles have found themselves victims of the power glut. Independent power producers have announced plans to sell or close the 14-year-old Moss Landing power plant at Monterey Bay and the 13-year-old La Paloma facility in Kern County.

> Put simply, for the foreseeable future, we have more power plants than we need.
>
> — Mike Florio, former PUC commissioner

Robert Flexon, chief executive of independent power producer Dynegy Inc., which owns Moss Landing, said California energy policy makes it difficult for normal market competition. Independent plants are closing early, he said, because regulators favor utility companies over other power producers.

"It's not a game we can win," Flexon said.

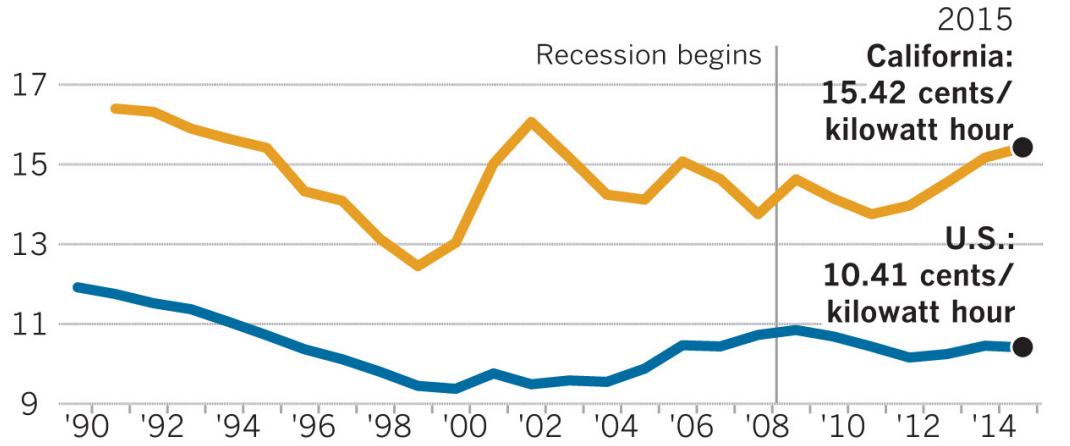
Since 2008 alone — when consumption began falling — about 30 new power plants approved by California regulators have started producing electricity. These plants account for the vast majority of the 17% increase in the potential electricity supply in the state during that period.

Hundreds of other small power plants, with production capacities too low to require the same level of review by state regulators, have opened as well.

Most of the big new plants that regulators approved also operate at below 50% of their generating capacity.

So that California utilities can foot the bill for these plants, the amount they are allowed by regulators to charge ratepayers has increased to $40 billion annually from $33.5 billion, according to data from the U.S. Energy Information Administration. This has tacked on an additional $60 a year to the average residential power bill, adjusted for inflation.

Another way of looking at the impact on consumers: The average cost of electricity in the state is now 15.42 cents a kilowatt hour versus 10.41 cents for users in the rest of the U.S. The rate in California, adjusted for inflation, has increased 12% since 2008, while prices have declined nearly 3% elsewhere in the country.



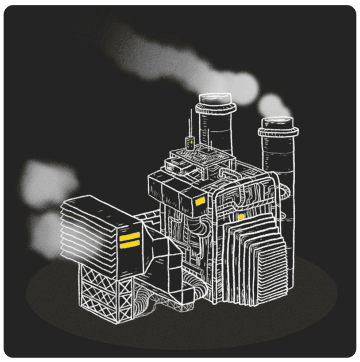
Note: cost of power figures are adjusted for inflation.
Source: Energy Information Administration
Graphics reporting by Ryan Menezes
@latimesgraphics

California utilities are "constantly crying wolf that we're always short of power and have all this need," said Bill Powers, a San Diego-based engineer and consumer advocate who has filed repeated objections with regulators to try to stop the approval of new plants. They are needlessly trying to attain a level of reliability that is a worst-case "act of God standard," he said.

Even with the growing glut of electricity, consumer critics have found that it is difficult to block the PUC from approving new ones.

In 2010, regulators considered a request by PG&E to build a $1.15-billion power plant in Contra Costa County east of San Francisco, over objections that there wasn't sufficient demand for its power. One skeptic was PUC commissioner Dian Grueneich. She warned that the plant wasn't needed and its construction would lead to higher electricity rates for consumers — on top of the 28% increase the PUC had allowed for PG&E over the previous five years.

The PUC was caught in a "time warp," she argued, in approving new plants as electricity use fell. "Our obligation is to ensure that our decisions have a legitimate factual basis and that ratepayers' interest are protected."



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California's energy supply: From blackouts to glut (/projects/la-fi-electricity-capacity-graphic/)

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Her protests were ignored. By a 4-to-1 vote, with Grueneich the lone dissenter, the commissioners approved the building of the plant.

Consumer advocates then went to court to stop the project, resulting in a rare victory against the PUC. In February 2014, the California Court of Appeals overturned the commission, ruling there was no evidence the plant was needed.

Recent efforts to get courts to block several other PUC-approved plants have failed, however, so the projects are moving forward.

Contact the reporters (mailto:ivan.penn@latimes.com; ryan.menezes@latimes.com?subject=The Power Boom). For more coverage follow @ivanlpenn (https://twitter.com/ivanlpenn) and @ryanvmenezes (https://twitter.com/ryanvmenezes)

Times data editor Ben Welsh contributed to this report. Illustrations by Eben McCue. Graphics by Priya Krishnakumar and Paul Duginski. Produced by Lily Mihalik

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cray.gnav Rank 0

Love the graphics but the perspective is 100% false. I know we live in a post-fact world but journalism, like science, lets the evidence tell the story. It's apparent in this writing that you had a desired outcome at the outset. I don't even live in California and nor do I have years of energy experience

yet I do know that #1 Californians use less energy per person than any other state, about half!, and that's due to recently deceased Art Rosenfeld who through a life time of energy efficiency... » more

27 days ago ▲ 0 ▼ 0 Reply Share

cate001 Rank 0

Very interesting article. I am curious how many of these 500 new power plants are solar or wind plants? The article gives the impression they are all gas power plants, but that can't be the case really.

1 month ago ▲ 1 ▼ 0 Reply Share

solartopia1 Rank 0

SHUT DIABLO CANYON. ALL THIS CAPACITY KILLS THE LIE THAT THOSE TWO HORRIBLE REACTORS SERVE ANY PURPOSE. SHUT THEM DOWN NOW!!!!

1 month ago ▲ 0 ▼ 4 Reply Share

mike.salva Rank 0

@solartopia1 Please return to Mexico you simpleton!!

1 month ago ▲ 2 ▼ 0 Reply Share

John Beckwith Rank 0

This article is so full of it.

We STILL are warned of rolling blackouts, despite the fact that they were fake all along. What I mean by that is, some local power plants were intentionally shut down to create a shortage. Its all well documented in the FERC report on our 2000 energy crisis.

We've all been told, and forced to conserve electricity for the last 18 years. We have been paying high rates all this time.

And you want to tell me its because we have too much of it? And because we... » more

1 month ago ▲ 2 ▼ 0 Reply Share

jimbotimes Rank 0

It's time for true oversight and regulation over this madness; if the supposed regulators won't do it, then out they must go.

1 month ago 4 0 Reply Share

sliggoth Rank 0

If there is such an over abundance of electricity produced in California, why does the state consistently import so much of its electricity?

25% imported in 2010 according to the eia, and that appears to have grown close to a third imported today. Perhaps that has something to do with the high cost of electricity?? At the very least the article should examine the complexity of the problem.

1 month ago 1 0 Reply Share

MDE 15 Rank 0

If California's power management is anything like its water management, even more problems can be expected in the future.

1 month ago 4 0 Reply Share

mulp Rank 40561

Sounds like Reagan supply side economics! Focus on increasing supply while ignoring who must pay for the supply.

Very Reagan conservative to build excess power plants!

2 months ago 1 1 Reply Share

John Beckwith Rank 0

@mulp

This state is OWNED by democrats. Quit trying to tie this into a conservative issue. The only part of this article which has to do with conservatives is more like "conservation", we all were forced to conserve and pay a high price for electricity starting a long long time ago. And now they say we have too much because we are using less and THAT IS the

reason why our costs are up???
This is about Democrats, environmentalists and poor management.
I'm not buying buying into this... » more

1 month ago 3 1 Reply Share

cgmiller128 Rank 0

@mulp I'm pretty liberal myself and I have to go with @John Beckwith on this. This is surely a democrat social safety net issue relying on ratepayers to fit the bill. A more conservative approach would be to allow for a freer market and for power plants to duke it out rather than give preference to natural monopolies.

1 month ago 0 0 Reply Share

sonja_and_andy Rank 0

I am really surprised that the article does not mention that California pursuing a goal of 100 percent zero-emission light-duty vehicles, according to Plug-In America - meaning electrical vehicles. This has been all over the EV magazines and renewable energy forums - of course they need to ramp up electricity production first, how else should they power the expected millions of electrical vehicles?

2 months ago 0 0 Reply Share

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sonja_and_andy Rank 0

@plantessa California has long term plans to switch all transportation to electrical. If power production is not ramped up now there will be a bottleneck down the road. While time-of-use metering is great, and I fully support it and have petitioned my own utility for it other people fight TOU for "social" reasons too, so it's often harder to implement that you'd think. Here for 2 years the consumers have been asked for TOU rates, and the PUC and utilities refuse, based on a few activists that... » more

1 month ago 1 0 Reply Share

cgmiller128 Rank 0

@sonja_and_andy I agree with the concept. But you don't ramp up an input in hopes of future demand while people have to pay for an unneeded resource. The EV market should naturally cause for more demand in

electricity in due time. It's not like the state needs to build a lot of plants to bolster innovation. There isn't much innovation to be had with natural gas.

1 month ago ▲ 1 ▼ 0 Reply Share

Dittto Rank 4074

What about the billions being spent on windmills ans solar farms that can be so unreliable as a power source.

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Analyst Note

Oct 2017

2030 Allowances Price and GHG Emissions Forecast for WCI Carbon Market

Chandan Kumar
Lead Economist
chandan@californiacarbon.info

Executive Summary: Based on the data on 2015 emissions, released by California Air Resources Board (ARB), the covered sector emissions accounted for 77.3% of the economy wide GHG emissions. It stands at 340.32 $MMTCO_2e$ compared to the California's greenhouse gas emissions inventory of 440.4 $MMTCO_2e$ for the year 2015.

Using time-series econometric analysis, it is expected that the greenhouse gas emissions from the covered sectors is likely to decrease from 340.3 $MMTCO_2e$ in 2015 to 322.4 $MMTCO_2e$, 309.9 $MMTCO_2e$ and 297.5 $MMTCO_2e$ in 2020, 2025 and 2030 respectively. It is expected to decrease at a higher rate post-2020 keeping macro economic growth, industrial growth rate, technological advancement and proposed sector specific emissions reductions target in mind.

The joint California-Quebec-Ontario allowance market is expected to remain oversupplied through 2020. Annual surplus turns into annual shortage in 2019, but average allowance prices move significantly away from the floor only after cumulative allowance shortage comes into play. With cumulative shortage in the range of 396 to 811 million tons, the 2030 allowance price is expected to significantly exceed the reserve price (US $30.77), in the range of US $91 to US $111 under different emissions and supply scenarios. Ontario is expected to face annual shortage from 2018 onwards and thus expected to be a net importer of compliance instruments from the other WCI members

To access other reports in this series, please visit http://californiacarbon.info/2030-sectoral-emission-forecasts/

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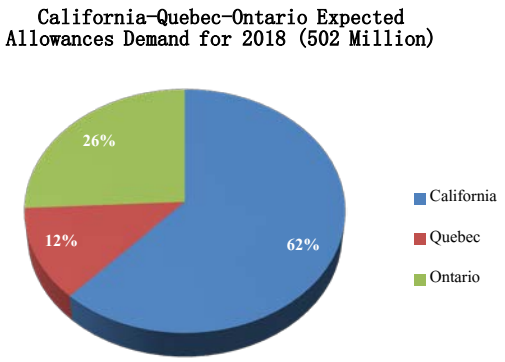
Overview of the WCI cap-and-trade program and market share of participants

Western Climate Initiative (WCI) – founded in February 2007 by the governors of five western U.S. states-Arizona, California, New Mexico, Oregon and Washington, with the goal of developing a multi-sector, market-based program to reduce greenhouse gas emissions. Presently it covers California and Quebec carbon market and expects Ontario to join in 2018. With introduction of Ontario, California carbon market will enjoy a share of 62% followed by Ontario-26% and Quebec-12% of the expected Carbon allowances demand in 2018.



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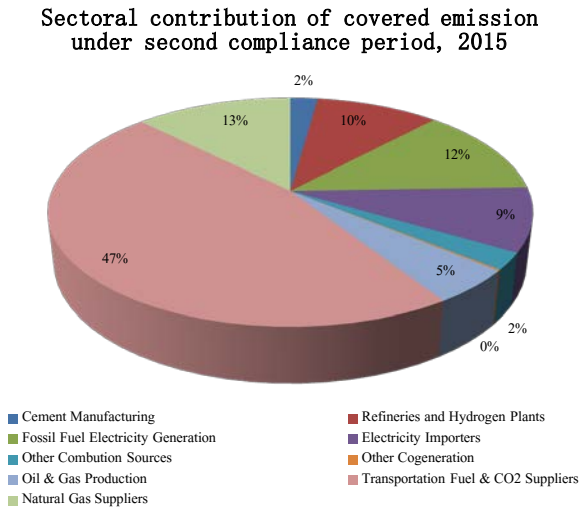
California Cap-and-Trade Program

California cap and trade is an economy-wide greenhouse gas emissions reduction program established under AB 32, in which market-based mechanisms help ensure goals are met in the most cost-efficient manner.

Overview of sectors covered under California cap-and-trade program



In 2015, an estimated 77% of California's emissions fell under the cap. Cap and trade first launched in 2012 with the following capped sectors: fossil fuel power generators; cement manufacturing; refineries & hydrogen plants; oil & gas production; other combustion sources; and electricity importers. It has expanded in 2015 to also include transportation fuel, and suppliers of natural gas. Based on reported emissions for 2015, the three largest sectors by GHG emissions are transportation fuel suppliers (47%), Natural Gas Suppliers (13%) and fossil power generation (12%).

California GHG Emissions forecast by sector

This analyst note aims to forecast the covered emissions of the above mentioned nine sectors that are covered under the California cap-and-trade program. This is done by generating forecast for the micro parameters associated with each sector in line with macro economic growth, fuel usage, changing dynamics of crude oil price and technological improvement along with complimentary measures and policy implication associated with each sector.

Forecast Methodology

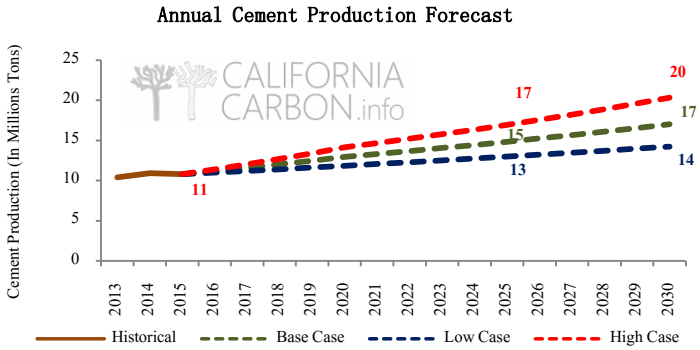
The Gross State Product (GSP) is one of the most important indicators of economic activity. Macro-level analysis suggests that development in an industrial sector has a very high correlation with the GSP growth rate, making the later a reliable indicator in the forecast of industrial parameters with reference to individual capped sectors in California.

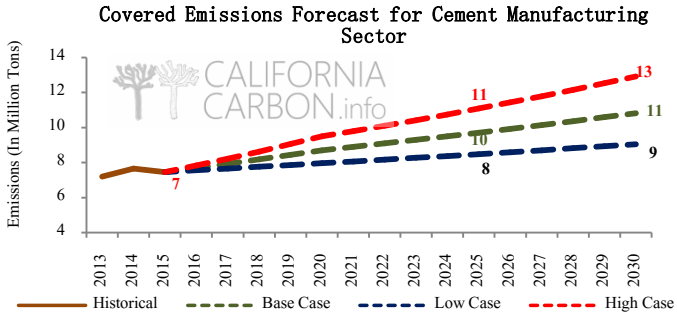
In order to account for all possible GSP growth rate scenarios, three alternatives are selected for this analysis:

- Reference scenario: 2.0% real GSP growth rate (2016-2020) and 1.5% 2021 onwards
- Optimistic scenario: 3.0% real GSP growth rate (2016-2020) and 2% 2021 onwards
- Pessimistic scenario: 0.5% real GSP growth rate.

Cement Manufacturing Sector

Out of 841 facilities who have reported their emissions in 2015, 10 entities fall under Cement manufacturing sector Together they cover approximately 2.2% of the total reported emissions in 2015. On an average, emission from this sector has increased by over 6% annually between 2010 and 2015. It is one of smaller sector but highly energy intensive. It is among one of those sector whose emissions are expected to increase despite of technological advancement as we expect cement production o increase at a rate of 3% annually between 2017 and 2030.



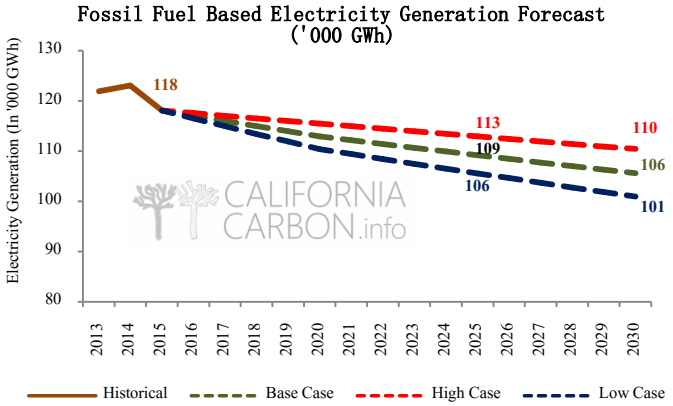


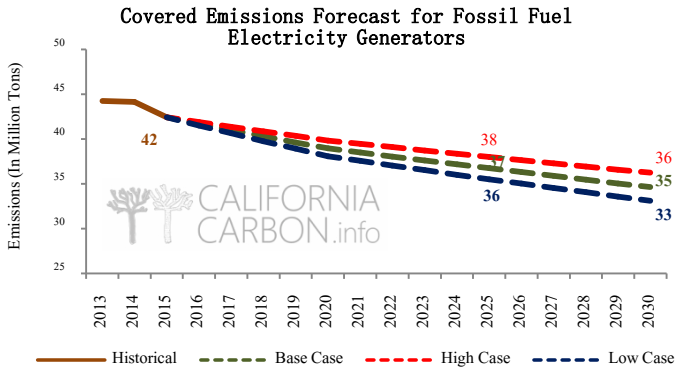
Reference real GSP growth scenario (2%:2015-2020),(1.5%: 2021-2030)

Cement Manufacturing	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**8.7**	**9.7**	**10.8**
Expected annual emissions growth:		**+2.51%**	
Cement Production Forecast (Million Tons)	**12.9**	**14.9**	**17.0**
Cement Production-GSP elasticity factor		**1.85**	
Emissions Factor (Emissions/Cement Production)	**0.67**	**0.65**	**0.64**

Fossil Fuel Based Electricity Generation

Out of 841 facilities who have reported their emissions in 2015, 151 entities fall under fossil fuel electricity generation sector. Together they cover approximately 12.5% of the total reported emissions in 2015. Covered Emissions from fossil fuel electricity generation registered a fall of 3.89% from 44.15 $MMTCO_2e$ in 2014 to 42.43 $MMTCO_2e$ in 2015. It is the biggest emitting sector following transport fuel suppliers. Emissions from this sector are expected to decline at a rate of over 1% annually between 2017 and 2030 as we expect a gradual decline in electricity generation from fossil fuel sources due to aggressive targets for renewable energy generation in the state. The increase in electricity demand with time is expected to be met by an increasing contribution from solar and wind.





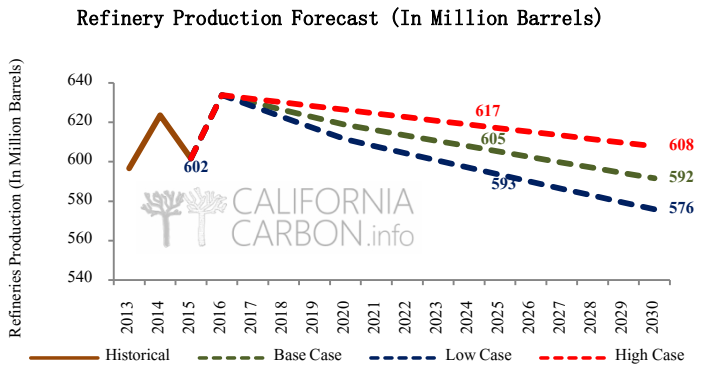
Reference real GSP growth scenario (2%:2015-2020),(1.5%: 2021-2030)

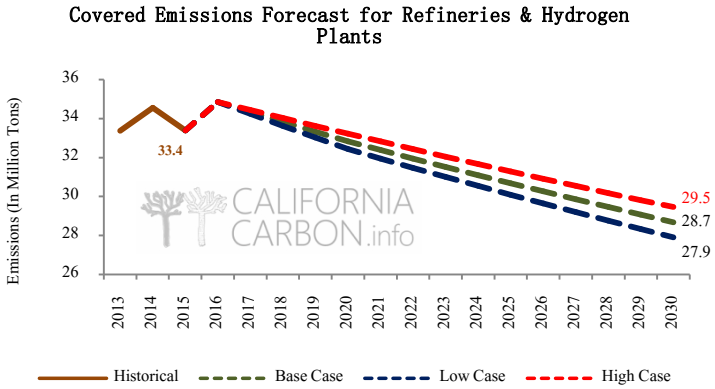
Fossil Fuel Electricity Generation	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	38.9	36.7	34.7
Expected annual emissions growth:		**-1.34%**	
Fossil Fuel Based Electricity Generation Forecast ('000 GWh)	**112.9**	**109.2**	**105.6**
Fossil Fuel Based Electricity Generation - GSP elasticity factor		**-0.45**	
Emissions Factor (Emissions (In Tons)/Fossil Fuel based Elec. Gen (KWh))	**0.35**	**0.34**	**0.33**

Refineries and Hydrogen Plants

Out of 841 facilities who have reported their emissions in 2015, 31 entities fall under refineries and hydrogen plants sector. Together they cover approximately 9.8% of the total reported emissions in 2015. Covered emissions from this sector registered a fall of 3.38% from 34.56 $MMTCO_2e$ in 2014 to 33.39 $MMTCO_2e$ in 2015. It is fourth largest GHG emitting sector under California cap-and-trade program.

Emissions from refineries are anticipated to decline at a steady rate with a more gradual gradient than that of the decline in the overall cap.





Reference real GSP growth scenario (2%:2015-2020),(1.5%: 2021-2030)

Refineries	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	32.8	30.7	28.7
Expected annual emissions growth:		-1.39%	
Refinery's Production Forecast (Million Barrels)	618.8	605.0	591.6
Refinery's Production-GSP elasticity factor:		-0.30	
Emissions Factor (Emissions (In Tons)/ Production (In '000 Barrels))	0.053	0.051	0.049

Electricity Importers

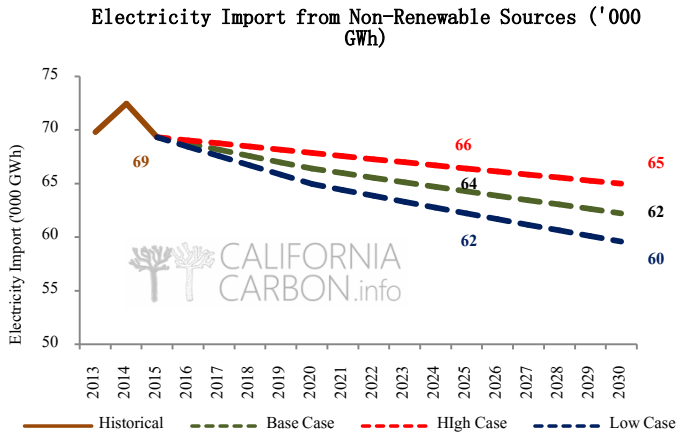
119 entities have reported emissions under electricity Importers in 2015. Together they cover approximately 9.03% of the total reported emissions in 2015. Covered Emissions from this sector registered a fall of 10.30% from 34.27 MMTCO2e in 2014 to 30.74 MMTCO2e in 2015. Emissions from electricity importers are expected to decline as we expect an increase in electricity imported from renewable source of energy. We also expect a fall of energy imported from unspecified sources having very high emissions factor.

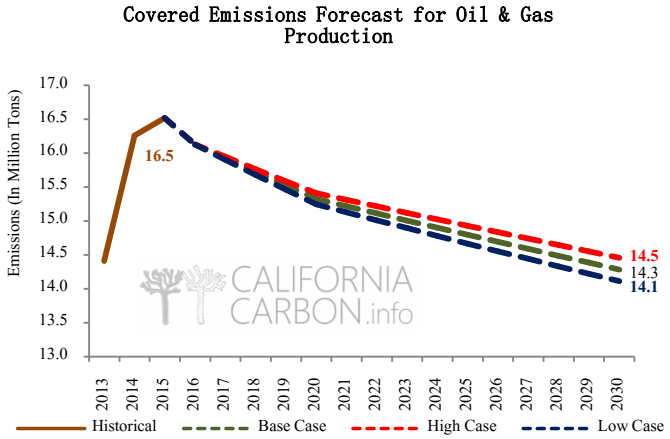
Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

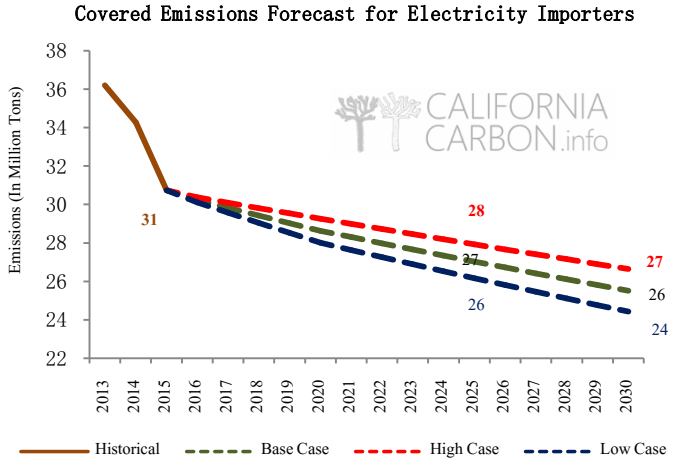
Electricity Importers	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	28.6	27.0	25.5
Expected annual emissions growth:		-1.23%	
Forecast for Electricity Import from Non-Renewable (TWh)	66.4	64.3	62.2
Energy Import-GSP elasticity factor:		-1.42	
Emissions Factor (Emissions (In Tons)/Non-Renewable Energy Import (In KWh))	0.429	0.421	0.410

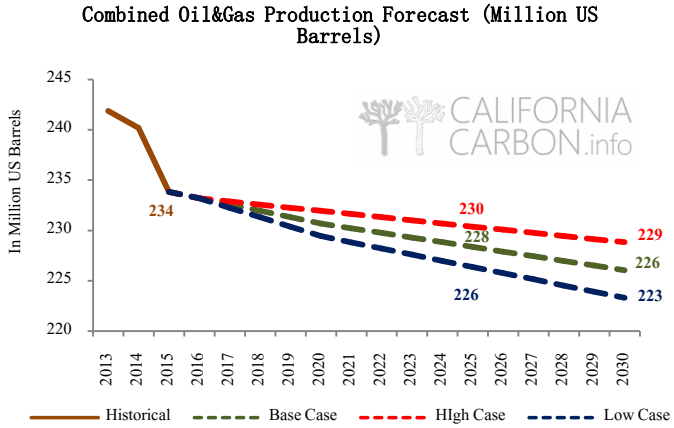
Oil and Gas Production

A total of 62 entities have reported emissions under oil and gas production sector in 2015. Together they cover approximately 4.85% of the total reported emissions in 2015. Covered Emissions from this sector registered a rise of 1.44% from 16.28 $MMTCO_2e$ in 2014 to 16.52 $MMTCO_2e$ in 2015.









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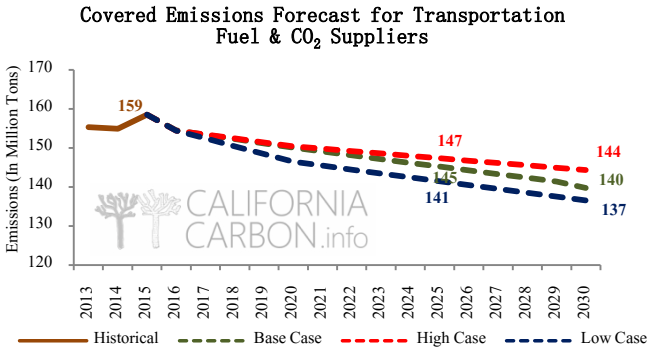
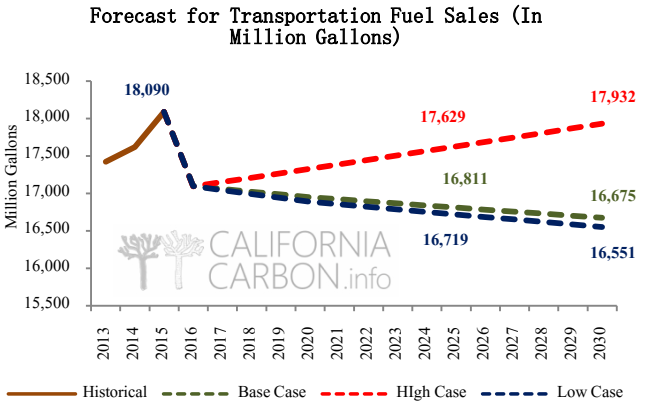
Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

Oil & Gas Production	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**15.3**	**14.8**	**14.3**
Expected annual emissions growth:		**-0.8%**	
Forecast for Combined Oil & Gas Production (Million US Barrels)	**230.7**	**228.4**	**226.1**
Oil & Gas Production-GSP elasticity factor		**-0.14**	
Emissions Factor (Emissions (In Tons)/Oil & Gas Production (In US Barrels))	**0.066**	**0.064**	**0.063**

Transportation Fuel & CO2 Suppliers

Out of 841 facilities who have reported their emissions in 2015, 57 entities fall under transportation fuel and CO_2 suppliers sector. Together they cover approximately 46.6% of the total reported emissions in 2015. Covered Emissions from this sector registered a jump of 2.33% from 1544.89 $MMTCO_2e$ in 2014 to 158.51 $MMTCO_2e$ in 2015. Transportation Fuel (TF) Suppliers are the largest GHG emitting sector in California and without any provisions for industrial assistance are major price drivers in the California carbon market. Among the various components of TF, only Jet fuel has registered an increase in total market sale. Other than that, gasoline and diesel have both been on decline for the last couple of years.



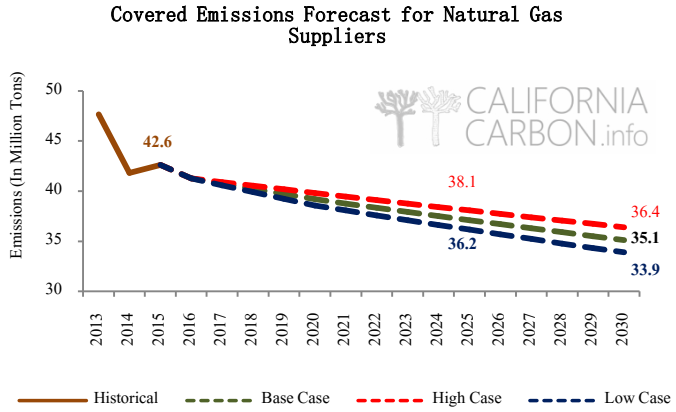


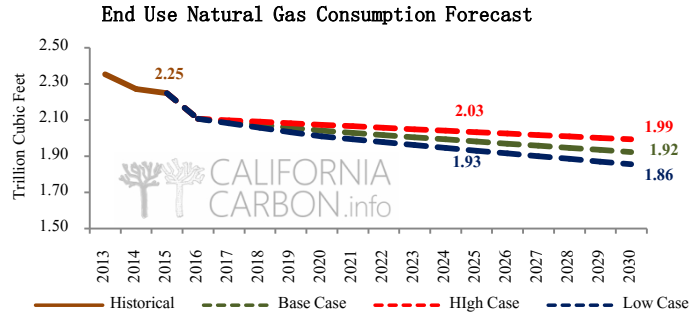
Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

Transportation Fuel & CO2 Suppliers	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**150.1**	**145.2**	**139.7**
Expected annual emissions growth:		**-0.84%**	
Forecast for Transportation Fuel Sales (Billion Gallons)	**16.95**	**16.81**	**16.67**
Transportation Fuel Sales-GSP elasticity factor		**-0.11**	
Emissions Factor (Emissions (In Tons)/Sales of Transportation Fuel (In '000 Gallons))	**8.85**	**8.64**	**8.38**

Natural Gas Suppliers

Natural Gas suppliers are the second largest GHG emitting sector in California. 41 entities have reported emissions under Natural Gas Suppliers sector in 2015.Together they cover approximately 12.53% of the total reported emissions in 2015. Covered Emissions from this sector registered a rise of 1.99% from 41.79 MMTCO2e in 2014 to 42.63 MMTCO2e in 2015.





Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

Natural Gas Suppliers	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**39.2**	**37.1**	**35.1**
Expected annual emissions growth		**-1.28%**	
Forecast for End Use Natural Gas Consumption (Trillion Cubic Feet)	**2.04**	**1.98**	**1.92**
End Use NG Consumption-GSP elasticity factor		**-0.39**	
Emissions Factor (Emissions (In Tons)/End Use NG Consumption (In '000 Cubic Feet))	**0.019**	**0.018**	**0.018**

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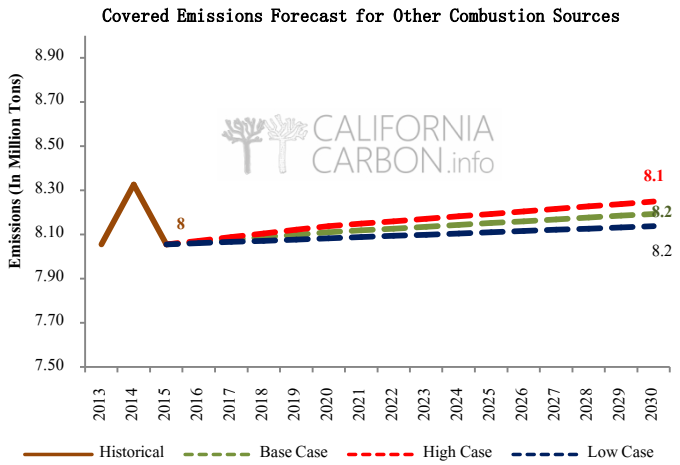
Other Combustion Sources

For the reporting year 2015, 277 facilities have reported their emissions under the other combustion sources. Together they cover approximately 2.37% of the total reported emissions in 2015. Covered Emissions from this sector registered a fall of 3.26% from 8.33 $MMTCO_2e$ in 2014 to 8.06 $MMTCO_2e$ in 2015.

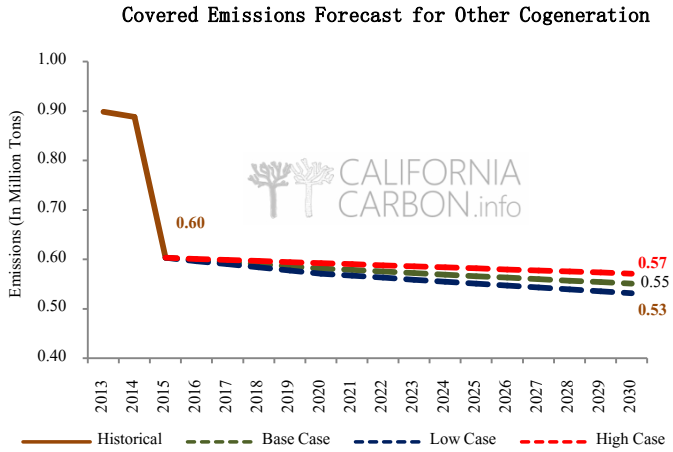
Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

Other Combustion Sources	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**8.11**	**8.15**	**8.2**
Expected annual emissions growth		**+0.11%**	
Emissions-GSP elasticity factor		**0.07**	



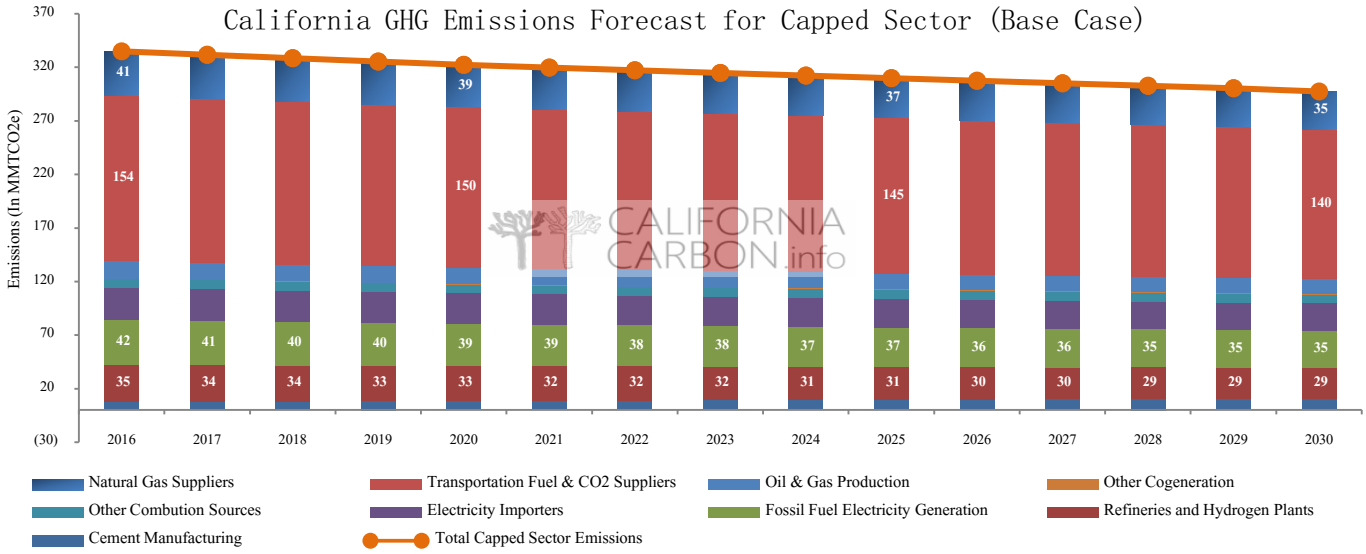
Other Cogeneration

93 entities have reported emissions under other cogeneration sector (excluding fossil fuel electricity generation) .Together they cover approximately 0.18% of the total reported emissions in 2015. Covered Emissions from this sector registered a fall of 32.11% from 0.89 $MMTCO_2e$ in 2014 to 0.60 $MMTCO_2e$ in 2015.

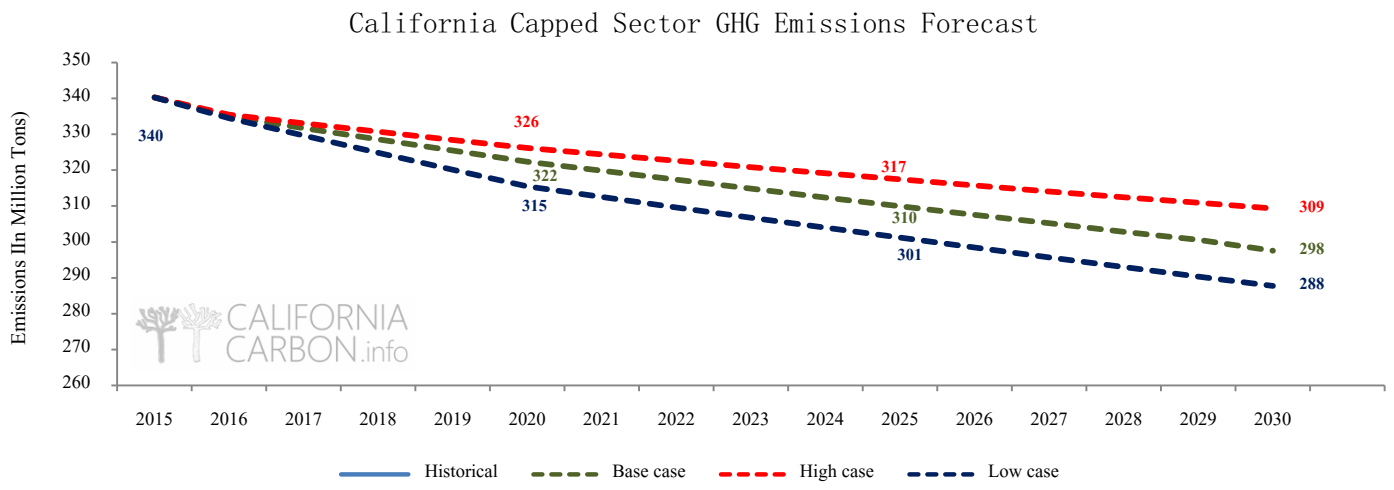


Reference real GSP growth scenario (2%:2015-2020), (1.5%: 2021-2030)

Other Cogeneration	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**0.58**	**0.57**	**0.55**
Expected annual emissions growth		**-0.60%**	
Emissions-GSP elasticity factor		**-0.36**	



California Covered Emissions Forecast



California Capped Sector GHG Emissions Forecast

Base Case

California Capped Sector	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**322.4**	**309.9**	**297.5**
Expected annual emissions growth		**-0.89%**	

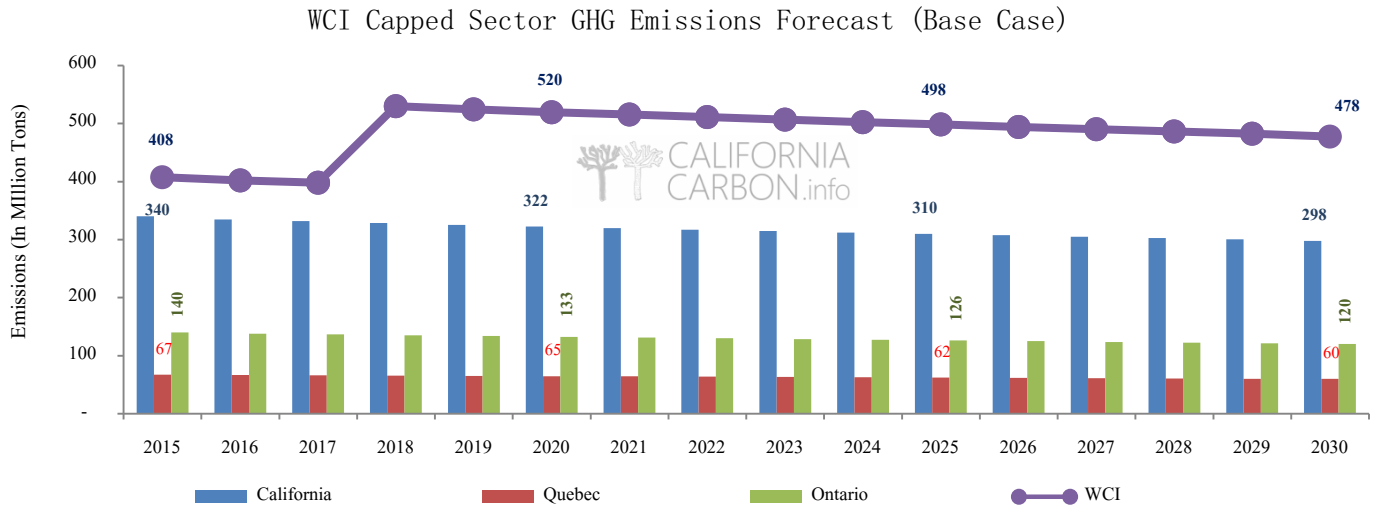
High Emissions Scenario

California Capped Sector	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**326.4**	**317.4**	**309.3**
Expected annual emissions growth		**-0.64%**	

Low Emissions Scenario

California Capped Sector	2020	2025	2030
Forecast emissions ($MMTCO_2e$)	**315.4**	**301.1**	**287.7**
Expected annual emissions growth		**-0.97%**	

WCI Capped Sector GHG Emissions Forecast



Demand for compliance instruments (Offsets and allowances)

Cap-and-trade compliance obligations may be met by surrendering either a CCA or an offset credit for each metric ton of CO2e emitted by an entity. ARB allocates the majority of CCAs freely during the initial years of the program, but the amount of free issuances decrease over time. Most notably, no free issuances are made to the largest two emitting sectors – transportation fuels and natural gas suppliers. Participants can also buy CCAs through ARB conducted auctions or by trading in the secondary market. Offsets may be used to meet up to 8 % of an entity's obligation till 2020. This is decreased for the next decade (2021-2030) for entities in California who can use a maximum of 4% between 2021 and 2025; 6% between 2026 and 2030 respectively of their compliance obligation. Furthermore, out-of-state offsets cannot make more than half of the abovementioned maximums.

Offset usage for California

To date the California Air Resources Board has issued over 66.4 million carbon offsets to over 288 projects. The total number of California Carbon Offsets (CCOs) available for future compliance stands at 37.7 millions taking into account those offsets which have been retired in previous compliance periods, forestry credits that are contained in a buffer pool for insurance purposes, and a small number of credits that have been invalidated.

Whilst a large number of registered credits (ROCs) as well as a high number of forestry projects in the pipeline promise a healthy supply of offsets in the short term, offset supply is anticipated to be well short of demand in the longer term.

California's in-state projects have been the lead providers of offset credits with 16.4 million CCOs being issued across 31 separate projects. Provisions within the latest extension bill (AB398) have proposed reducing the current offset usage limit of 8% to 4% from 2021-2025 with a minimum mandate of 50% per entity from offsets that provide air quality and water quality benefits in California. From 2026 to 2030 an offset usage limit of 6% would exist with the same 50% carveout for in-state offset projects. Under current scenarios, the supply of Californian offsets would pose further constraints to the total use of offsets within the program. Since AB398 has been written into law, the supply of offsets within California will therefore have an increasing importance to not only emission reduction projects across the country but also CCA prices.

Methodologies, Assumptions and Findings

With regard to key assumptions for in-state offset supply, a three-part approach has been taken to model the future volumes of offsets from California in-state projects currently listed amongst the Offset Project Registries.

It is assumed that only projects listed under the forestry and livestock projects would meet the AB398 mandate of in-state offset credits that provide air and water quality benefits. Although substances destroyed under the Ozone Depleting Substance protocol may well be collected within California, the location of the destruction facilities out of state discredit their inclusion within this report. Credits in the buffer pool are not considered for the analysis.

The analysis of offset supply from in-state California projects included calculating future CCO volumes 2020-2030 from: 1) Projects that have already been issued CCOs 2) Projects that have been issued ROCs that are pending conversion to CCOs by ARB 3) Projects that are listed, but have not been issued any credits to date. Based on this analysis, the total volume of California in-state offsets expected to be generated 2020-2030 is 12,145,751 credits. Details are provided below.

	Forestry	Livestock	Total
CCO Credited projects	3,081,734	329,012	3,410,746
ROC Credited projects	337,559	134741	472300
Listed projects	7,712,641	550,064	8,262,705
Total	11,131,934	1,013,817	12145751

1. *Volume of Offsets from Future Reporting Periods of Credited Compliance Projects:*

Credits from future reporting periods (RP) from existing and upcoming Forestry and Livestock projects in California have been considered. This step takes into consideration future reporting periods from credited CCO projects, excluding those that have been assigned ROCs (accounted for separately below). In total, there are 17 projects that fit these criteria. It is assumed that all these projects will be assigned subsequent credits for their next reporting period. In order to calculate this volume, statistical analysis has been used to calculate a co-efficient for the volume of

credits issued from the first RP (RP1) to the second RP (RP2) for both livestock and forestry credits. An average turnover rate for RP2-RP3 and RP3-RP4 has been assumed based on the best available data.

2.) *Backlog of registered credits (ROCs) pending conversion:*

At time of writing 15 reporting periods (RP) (2 from the livestock protocol and 13 forestry) have been awarded ROCs that are awaiting final ARB approval before being converted to CCOs. Assuming all ROCs are converted, this step gives the impending supply of CCO volume over the near future. The median lead time for ROC-CCO issuance is 57 days for livestock credits and 98 for forestry projects.

An anticipated 4,339,805 credits from issued ROCs are expected to be converted to CCOs by ARB. Whilst some of these projects are overdue, this supply is expected to enter the market over the coming year. An additional 472,300 credits is calculated from future reporting periods of these projects. 134,741 of these credits will come from livestock projects with forestry projects accounting for the remainder.

3.) *Expected issuances from listed, unaccredited projects Forestry credits based on acreage:*

There are 38 forestry projects listed that have not yet been credited with either ROCs or ARBOCs. Due to the scale of forestry projects, the projected volume these projects will yield is significant to the future supply of Californian offsets.

A large number of forestry projects were listed prior to protocol changes made in 2015. While not all of these may be developed and issue credits, it is assumed that all projects will go forward.

To forecast the potential volume for RP1 from these projects, statistical analysis has been used to determine offset volume based on the projects size (acreage). RP2 of Improved Forest Management (IFM) projects were found to yield around 5.4% of the first reporting period.

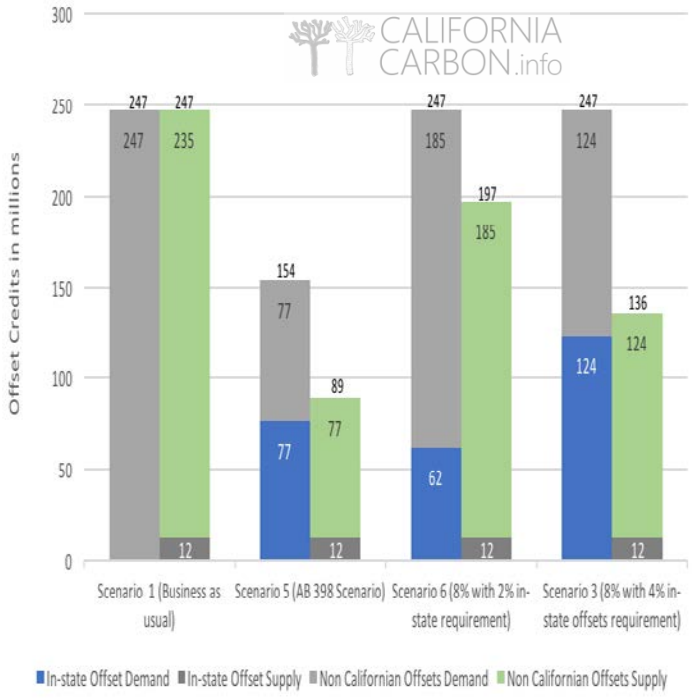
It is calculated that 9.9 million credits from initial reporting periods could be unlocked should all of the IFM forestry projects listed under the 2015 protocol come to fruition.

Livestock projects: Only 5 livestock projects are yet to gear up for issuances. It is assumed these projects will gain the average, 18,245, number of credits for their first reporting period.

Far smaller in size and with a lower backlog of projects, 91,225 credits are estimated from the RP1 of listed livestock projects

Conclusion The analysis of offset supply from California projects, even while considering only credits from the existing and pipeline of listed projects, is results in only 12 million tons 2020-2030, which pales in comparison with the overall potential offset demand. A comparison of actual 2020-2030 potential demand with offset supply is provided below to further highlight this fact under different scenarios based on CaliforniaCarbon.info's offset demand forecast for in-state offset projects

Total Potential Offset Demand Vs Offset Supply from Various Scenarios



Offset usage for Quebec

Offset credits in Quebec are earned by project activities under one of MDDELCC's approved offset project types. To date, Quebec has approved three offset project types: (i) methane destruction as part of project to cover manure storage facility, (ii) Capture of gas from certain landfill sites, and (iii) Destruction of certain ODS contained in insulating foam recovered from appliances.

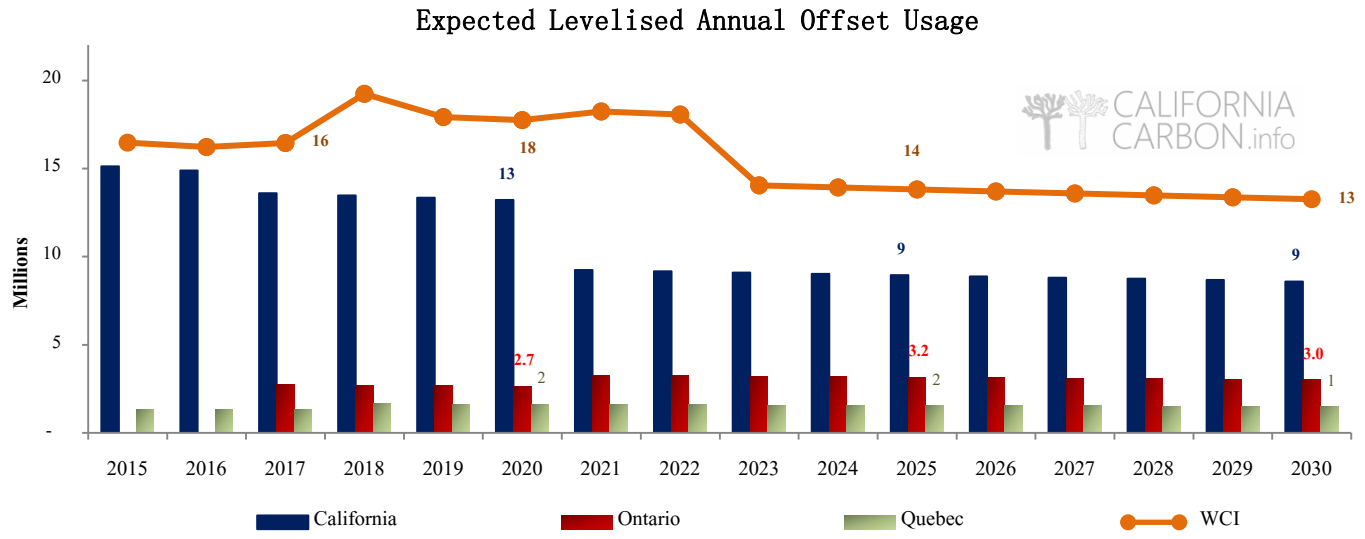
The level of offset demand that may conservatively be expected in the WCI cap-and-trade is estimated hereby: Entities with annual covered emissions higher than 10 MMtCO2e are assumed to use offsets for 8% of their compliance; entities with annual emissions between 10 and 15 MMtCO2e are assumed to use 6- 7%; entities with annual emissions between 5 and 10 MMtCO2e are assumed to use 5%; entities with annual emissions between 2.5 and 5 MMtCO2e are assumed to use 3%; while entities with annual emissions under 2.5 MMtCO2e are assumed to use 2%.

Based on these assumptions for calculating offset demand, most Quebec entities covered under CP1 come in the last category (i.e. below 2.5 MMtCO2e). Their offset usage is modeled to increase over time (i.e. 1.5 % of annual obligations in CP2, 2.0% of annual obligations in CP3, and approximately 2.5% of annual obligations after 2020). This gives a cumulative offset usage of roughly 24.4 million before 2030. For Quebec based entities, the offsets credit generated under Quebec's offset protocol can't be invalidated. However, due to the lack of offset credit generation from these protocols, Quebec is expected to be net buyers of offsets from California. Additionally, buying offsets from California has its own disadvantages, such as the risk of invalidation associated with CCOs. It also includes currency risk i.e. foreign exchange rate risk involved in primary contract. There is an additional cross border litigation cost as well as a surveillance cost in case of any dispute.

Under the Ontario cap-and-trade proposed regulation, covered emitters will likely be able to use credits generated by qualifying offset projects to meet up to 8% of their compliance obligations. Since offset programs aim to expand emission reduction benefits beyond the coverage of the cap, Ontario is expected to initially include protocols from waste management (landfill methane) and agriculture - the two largest sectors in the province not covered the cap.

Other potential protocols for offset generation may include mine methane capture and destruction and ozone-depleting substance capture and destruction. Based on the above assumptions for calculating offset demand, most Ontario entities covered under CP1 (2017-2020) come in the last category (i.e. below 2.5 MMtCO2e) except ArcelorMittal Dofasco Inc. with annual emissions of over 5 MMtCO2e for 2013.

In sum, our model gives Ontario a cumulative offset usage of roughly 42.2 million before 2030. Due to the lack of generation from these expected protocols, Ontario is expected to be a net buyer of California and Quebec offsets in the initial year of its cap-and-trade program.



Demand-supply situation for allowances

California allowance demand and supply

Annual allowance budget for California 2013-2020

Compliance Year	Allowances (millions)
2013	162.8
2014	159.7
2015	394.5
2016	382.4
2017	370.4
2018	358.3
2019	346.3
2020	334.2
Total	2,508.6

Source: ARB (2013)

The first annual cap in 2013 was set at 162.8 million and reduced by 2% in 2014. In 2015, the inclusion of new sectors like transport fuels and natural gas suppliers more than doubled the annual cap to 394.5 million. It has been declining by approximately 3% every year thereafter and is expected to stand at 334.2 million in 2020.

2030 allowance budget estimation for California

The total allowance budget in California post-2020 is extended from the 2020 cap to meet the 2030 emissions target of 40% below 1990 level.

The supply side of the forecast model is taken as the value of the cap for each compliance year after adjusting for allowances withheld under the Allowance Price Containment Reserve (APCR).

Demand for allowances is assumed to equal projected capped emissions adjusted for reductions due to leakage and offset usage.

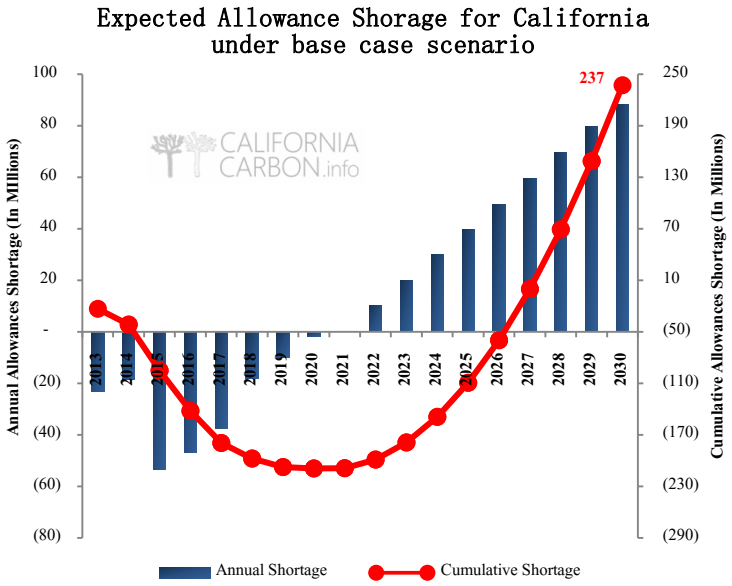
Allowance Price Containment Reserve (APCR): 2021-2030

The volume of allowances held in the APCR is calculated in accordance with AB398 wherein two-thirds of the allowances remaining in the reserve by the end of 2017 would be divided equally between the two APCR tiers after 2020. The Final Regulation Order of Scoping plan (effective from October 01, 2017) would assign a further 10.5 million allowances into the APCR in 2021. This would be reduced by 1.1 million every year to reach zero by 2030.

We estimate the percentage of the annual cap post-2020 that would be assigned into the two APCR tiers (divided equally between both) would be as detailed below:

Compliance Year	% of Cap (Expected)
2021	3.44%
2022	3.22%
2023	2.98%
2024	2.71%
2025	2.42%
2026	2.05%
2027	1.69%
2028	1.27%
2029	0.81%
2030	0.00%

In addition to the two APCR tiers, a price ceiling with a higher trigger point would also be established permitting the regulators to assign non-tradable allowances at the ceiling price as needed. Allowances remaining in the APCR by 2020 will be assigned to the price ceiling reserve. We assume that new allowances issued through the price ceiling mechanism would not exceed the shortage seen for any of the years that the price ceiling is triggered.



Under the baseline demand and baseline supply scenario, there is an annual shortage of approximately 88.4 million for the 2030 compliance year alone and a cumulative shortage of approximately 237.2 million allowances for the entire period of 2013-2030.

Quebec allowance demand and supply

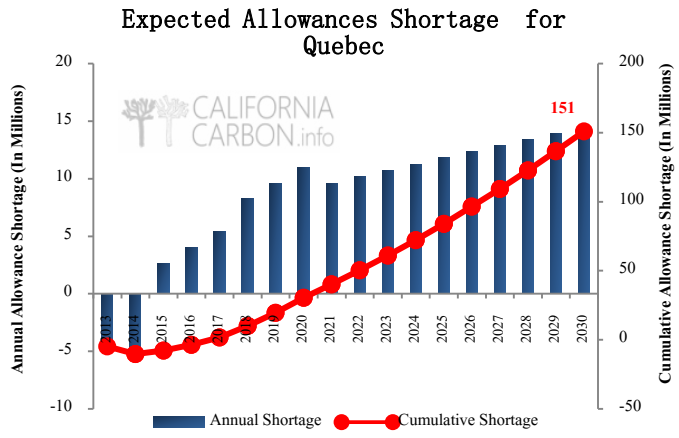
Annual economy-wide allowance budget for Quebec

Compliance Year	Allowances (millions)
2013	23.2
2014	23.2
2015	65.3
2016	63.19
2017	61.08
2018	58.96
2019	56.85
2020	54.74
Total	406.52

Quebec's annual allowance budget was defined as 23.2 million for both 2013 and 2014, rising to 65.3 million with the inclusion of new CP2 sectors in 2015. The provincial cap is decreased approximately 3.5% every year thereafter until 2020 when it will stand at 54.7 million.

2030 Quebec allowance budget scenarios

In line with the 2020 emissions reduction target for the Quebec cap-and-trade program and the proposed 2030 emission reduction target of 37.5% below 1990, we anticipate annual allowance budgets for Quebec between 2021 and 2030. The supply side of the model is derived after adjusting the annual to reflect withholdings for the APCR.



The baseline demand and supply scenarios yield an annual shortage of approximately 15.6 million for 2030, and a cumulative shortage of 169.8 million for 2013-2030.

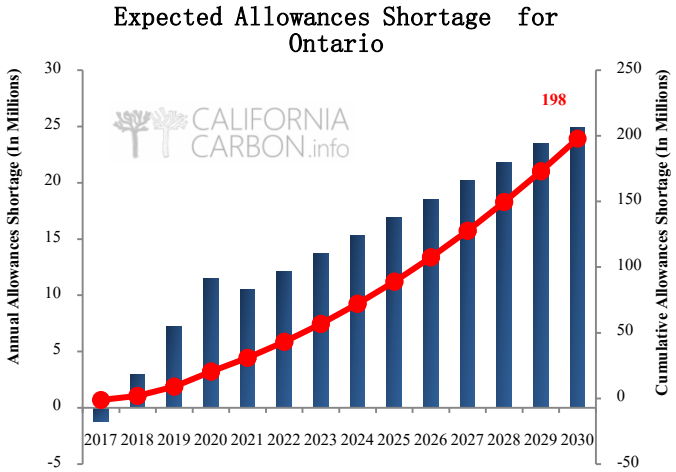
Ontario allowance demand and supply

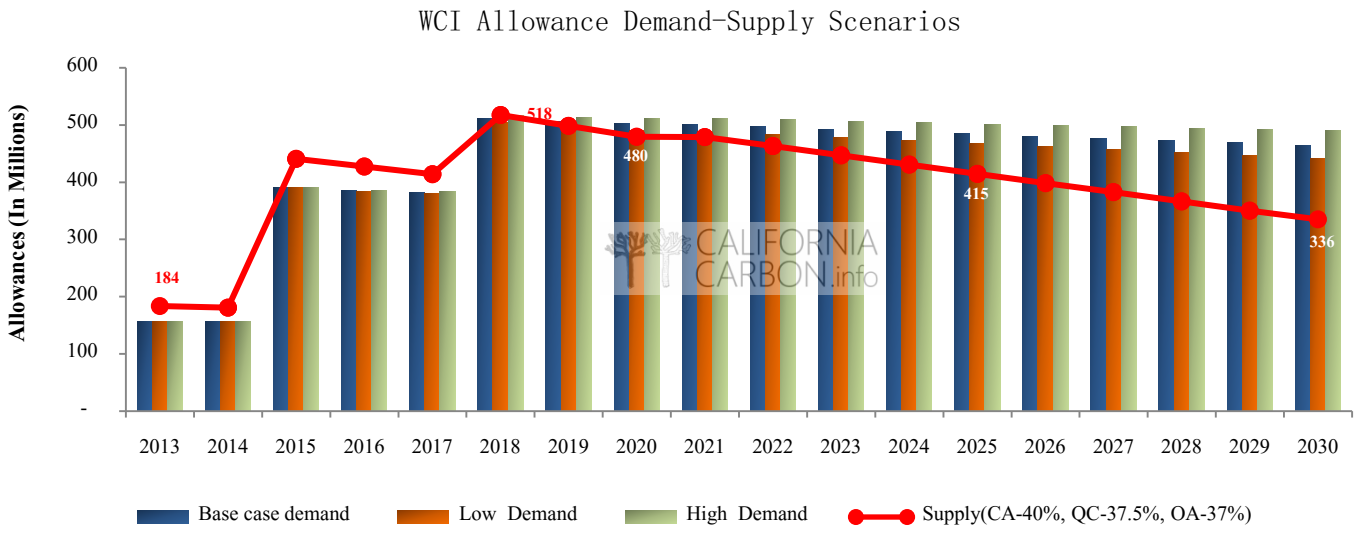
Annual economy-wide allowance budget for Ontario

Compliance Year	Allowances (millions)
2017	142.3
2018	136.4
2019	130.6
2020	124.7
Total	**533.9**

Ontario's annual allowances budget is proposed as 142.3 million for 2017. It falls by approximately 4.3% every year thereafter until 2020, when it will stand at 124.7 million. In line with 2020 reduction target and allowances budget for Ontario cap-and-trade program till 2020 and the proposed emissions reduction target of 37% below 1990 level by 2030, we anticipated the annual allowances budget for the period 2021-2030. The allowances budget is expected to decline by 7% every year from 2021-2030 to reach 92.4 million from 124.7 million in 2020

Under the baseline demand and supply scenarios, an annual shortage of some 24.9 million for the 2030 compliance year and a cumulative shortage of some 197.9 million across 2017-2030, are expected. The cumulative shortage for an Ontario stand-alone market would trigger as early as 2018.





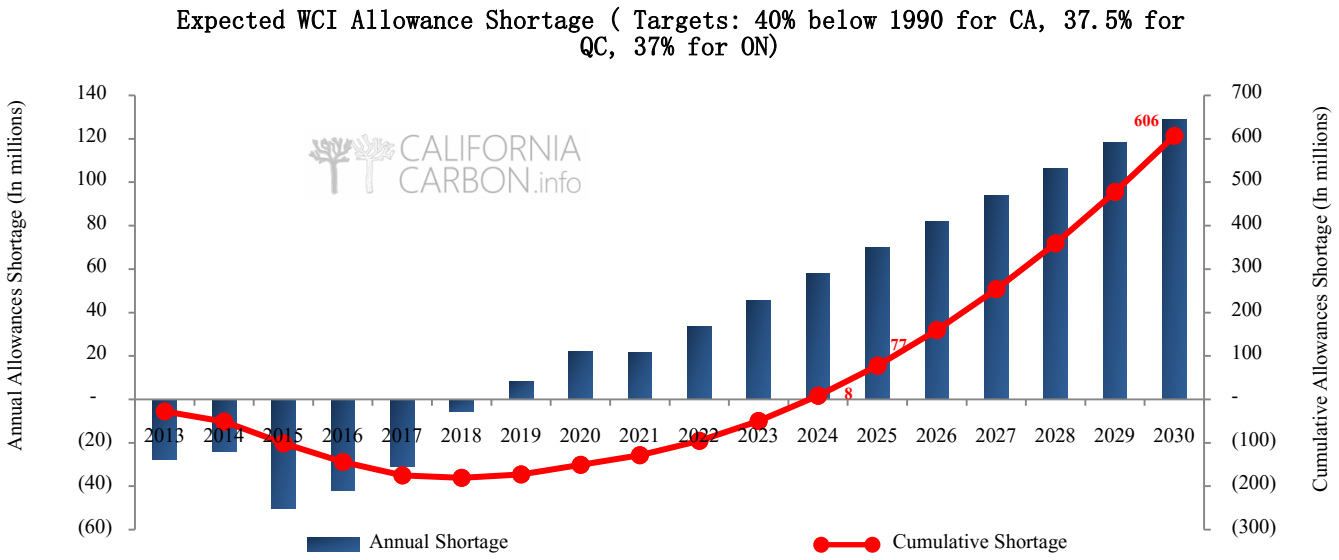
Projected WCI supply-demand situation

On January 1, 2014 the California and Quebec cap-and-trade systems officially linked, enabling the mutual

acceptance of either jurisdiction's compliance instruments. They had their first joint auction for allowances in November 2014.

California accounts for a projected 62% of combined emissions in 2018, followed by Ontario at 26%, and lastly Quebec at 12%.

The baseline demand and supply scenarios create a shortage of approximately 128.9 million for the single 2030 compliance year, and a cumulative shortage of 606.2 million for 2013-2030. Despite of a shortage of allowances in Ontario and Quebec, the triumvirate market will remain substantially oversupplied during the initial years. We estimate that 2019 will be the first year when allowances demand exceeds supply in the WCI carbon market. Thereafter, the annual supply falls short each year and erodes the existing carried over surplus in 2024.



Impact on WCI carbon price

The allowance price forecast estimates a spread between the annual reserve price and the average auction settlement price. Using historical auction price data, a relationship between average spread and applicable cumulative surplus/shortage for the WCI carbon market is derived. A similar relationship is used to forecast the annual average allowance price for each year from 2016 to 2030.

Reserve Price, APCR trigger price and Price Ceiling Projections

We use the exiting methodology of calculating the reserve price, i.e. increase the reserve price every year by 5% in real terms, to forecast the reserve prices in the California cap-and-trade program over the next decade. A conservative average inflation rate of 1.5% (2021-2030) is used, and thus, the Reserve Price increases at 6.5% every year during the period of 2021 to 2030.

Similarly, we expect a dynamic price ceiling which is raised annually by 5% plus an inflation rate. We start by assuming a price ceiling at USD 63 for 2021. The APCR trigger price is derived from the difference between the reserve price and the ceiling price for every year. For the APCR tier I trigger price, we add one-third of the difference between price ceiling and reserve price to the reserve price, and for APCR tier II trigger price, we add two-thirds of the difference to the reserve price.

APCR tier I trigger Price $_t$ = Reserve Price $_t$ + 1/3* (Price Ceiling $_t$ – Reserve Price $_t$)

APCR tier II trigger Price $_t$ = Reserve Price $_t$ + 2/3* (Price Ceiling $_t$ – Reserve Price $_t$)

Year	Price (US$)			
	Reserve Price	APCR Tier I trigger Price	APCR Tier II trigger Price	Price Ceiling
2021	17.46	32.6	47.8	63.0
2022	18.59	34.8	50.9	67.1
2023	19.80	37.0	54.2	71.5
2024	21.09	39.4	57.8	76.1
2025	22.46	42.0	61.5	81.0
2026	23.92	44.7	65.5	86.3
2027	25.47	47.6	69.8	91.9
2028	27.13	50.7	74.3	97.9
2029	28.89	54.0	79.1	104.3
2030	30.77	57.5	84.3	111.0

The shortage of allowances at each year will be met by releasing of allowances from APCR tier 1, APCR tier 2 at their respective prices for that year. The remaining allowances required to meet the compliance obligation for any year could be bought at the price ceiling of that year.

The baseline demand and supply scenarios would have created an annual surplus of 31.0 million in 2017. However, five consecutive undersubscribed auctions in 2016 and early 2017 resulted in approximately 154 million tons not entering the supply and awaiting re-introduction, thus causing a temporary shortage for the current year. However with two fully subscribed auctions, we expected market to be long again and result into a cumulative surplus of 54 million at end of 2017. This temporary shortage underpins an expected auction price spread of over 80 cents, with weighted clearing at approximately US$ 14.38. At present allowances, are traded well above the floor as participants anticipate a shortage in the long run.

In 2018, expected linkage of Ontario with California and Quebec is expected to soak up some of the existing surplus in the WCI carbon market. With a cumulative shortage of 1.8 millions of allowances coming from Ontario, the cumulative surplus in WCI carbon market is expected to increase at a diminishing rate from 175 million in surplus pre-linkage to 181 million in surplus post-linkage. This surplus is expected to produce an average price spread of 81 cents, with weighted average prices of US $15.25, approximately.

The annual surplus turns into an annual shortage in 2019, causing the cumulative surplus to decline to 173 million. This produces an average spread of 80 cents and an allowance price of just over US$ 16.20. The reduced cumulative surplus of 49.9 million in 2023 produces a spread of $1.15, and an allowance price of approximately US$ 20.95

With the cumulative surplus turning into a 7.7 million cumulative shortage in 2024, and we expect the APCR1 to trigger for the first time in that year. The cumulative allowances available in the APCR1 till 2024 stand at 49 million. Once the APCR1 is released, it is expected to get exhausted in anticipation of future shortages. Hence, average allowances price for 2024 is expected to be at US$39.43, US$ 18.34 above the reserve price.

A cumulative shortage of 28.4 million in 2025 will trigger APCR1 as well as APCR2. It will push the annual average

allowance price to be US$61.32, US$ 38.86 above the reserve price. With a cumulative shortage of over 51 million of allowances in 2026 assuming the fully subscribed auctions, over 43 million allowances will be bought at the price ceiling to meet the compliance obligation for 2026. It results in a weighted average allowances price for 2016 ofe US$67.35. Even though the annual shortage increases at a decreasing rate in the posto2020, a 2030 annual shortage of 129 million will need to be purchased at the price ceiling of US$ 111. It results into a weighted average allowances price of USD 91.71, US% 60.94 above the reserve price of US$30.77.

The graph below depicts expected annual average allowance prices for the WCI cap-and-trade program under different demand-supply assumptions. The average CCA price for 2020 is estimated in the range of US $17.00 - 17.07. With 2030 annual shortage expected to be in the range of 106 to 155 million allowances (depending on the scenario), average allowance price range from US $91.00 to US $111.0.

Year	Purchase of Allowances (In Millions)-Base Case			
	Auction	APCR1	APCR2	Price Ceiling
2021	479.56	-	-	-
2022	463.45	-	-	-
2023	447.25	-	-	-
2024	431.06	49.02	-	-
2025	415.00	4.84	53.86	-
2026	399.01	3.92	3.92	43.56
2027	382.89	3.07	33.27	57.55
2028	366.90	2.21	2.21	101.59
2029	350.85	1.32	1.32	115.58
2030	335.67	0.00	0.00	128.92

Year	Purchase of Allowances (In Millions)- Low Emissions Case			
	Auction	APCR1	APCR2	Price Ceiling
2021	479.6	0	0	0
2022	463.4	0	0	0
2023	447.2	0	0	0
2024	431.1	0	0	0
2025	415.0	0	0	0
2026	399.0	57.8	0	0
2027	382.9	3.1	60.9	0
2028	366.9	2.2	2.2	67.2
2029	350.8	1.3	1.3	93.9
2030	335.7	0	0	106.9

Year	Projected Reserve Price (US$)	Expected Average Allowance Price (US$)		
	Pt = Pt-1 x (105% + rate of inflation)	Baseline Emissions Scenario	Low Emissions Scenario	High Emissions Scenario
2016	12.73	12.73	12.73	12.73
2017	13.57	14.38	14.38	14.38
2018	14.45	15.25	15.24	15.26
2019	15.39	16.20	16.18	16.23
2020	16.39	17.24	17.19	17.29
2021	17.46	18.36	18.28	18.45
2022	18.59	19.57	19.44	19.57
2023	19.80	20.95	20.72	37.02
2024	21.09	39.43	22.13	57.55
2025	22.46	61.32	23.75	63.87
2026	23.92	67.35	44.72	69.22
2027	25.47	72.31	69.62	74.46
2028	27.13	79.27	77.81	80.10
2029	28.89	85.26	84.34	86.17
2030	30.77	91.71	90.75	92.73

Year	Purchase of Allowances (In Millions)-High Emissions Case			
	Auction	APCR1	APCR2	Price Ceiling
2021	479.6	0	0	0
2022	463.4	0	0	0
2023	447.2	43.3	0	0
2024	431.1	5.7	49.0	0
2025	415.0	4.8	4.8	63.6
2026	399.0	3.9	3.9	92.8
2027	382.9	3.1	3.1	108.3
2028	366.9	2.2	2.2	123.7
2029	350.8	1.3	1.3	139.3
2030	335.7	0	0	154.9

Conclusion

We expect the joint California-Quebec-Ontario allowance market to remain oversupplied through 2020. Annual surplus turns into annual shortage in 2019, but average allowance prices move significantly away from the floor only after cumulative allowance shortage comes into play. With annual shortage in the range of 106 to 155 million tons, the 2030 allowance price is expected to significantly exceed the reserve price (US $30.77), in the range of US $91 to US $111 under different emissions and supply scenarios. Ontario is expected to face annual shortage from 2018 onwards and thus expected to be a net importer of compliance instruments from the other WCI members.

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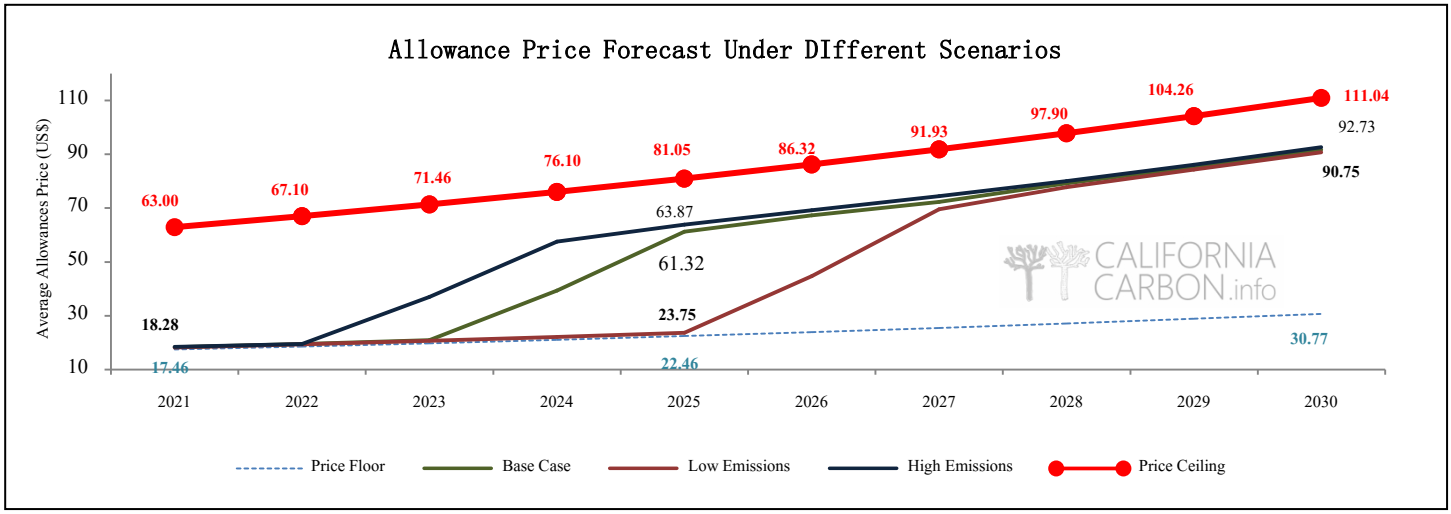
Impact of AB398

The passage of AB 398 with supermajority has given the much needed certainty to the longer run perspective of the cap-and-trade program. It has revitalized the market participant's confidence in the program which was clearly reflected by a jump in secondary market prices in the latter half of 2017.

However, a stricter offset usage regulation including a 50% instate carve out has its own implications in the longer run. It has increased the cumulative shortage at end of 2030 by over 150 million compared to an 8% offset usage scenario forecasted previously by CaliforniaCarbon.info. Compared to CaliforniaCarbon.Info's previous model with expected average offset usage of 4.1% of the compliance obligation annually, AB 398's new clauses results in an additional cumulative shortage of 40 million in 2030, while also controlling prices at a pre-determined ceiling for when the market supply falls short.



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Allowance Price Containment Reserve Analysis, Air Resource Board *https://www.arb.ca.gov/regact/2010/capandtrade10/capv3appg.pdf*

Equivalency Results

How are they calculated?

The sum of the greenhouse gas emissions you entered above is of Carbon Dioxide Equivalent. This is equivalent to:

415,000 Metric Tons

Greenhouse gas emissions from

88,865

Passenger vehicles driven for one year

-or-

1,017,156,863

Miles driven by an average passenger vehicle

-or-

144,599

Tons of waste recycled instead of landfilled

-or-

20,678

Garbage trucks of waste recycled instead of landfilled

CO_2 emissions from

46,697,423

gallons of gasoline consumed

-or-

454,048,140

Pounds of coal burned

-or-

Energy Exchange

REPORT: CA Utilities Are Leaking Lots of Gas – but There's a Way to Stop It

By Amanda Johnson | Published: March 1, 2017

A new report confirms with greater accuracy than ever before that California natural gas utilities are letting huge amounts of their product escape into the atmosphere – about 6.6 billion cubic feet in 2015. That's more than the amount of gas released during last year's Aliso Canyon disaster, and over twice the total loss from all of the state's oil and gas wells.

These huge gas losses are a major environmental problem. Methane – the main ingredient in natural gas – is a potent climate pollutant. Leaks and other emissions from California utilities in 2015 have the same climate impact as burning more than 1 billion gallons of gasoline.

Where the data comes from and what it means

In 2014 California passed SB 1371, a new law requiring utilities to reduce methane emissions. This new report is based on emissions data collected under that law.

The report estimates that about 78% of gas leaks occur at four kinds of sources: customer meter sets; metering and regulating stations; ungraded leaks; and intentional venting.

This data also allows the state to track progress against newly-legislated methane reduction goals, like the one included in SB 1383, which sets a target of 40% emissions reductions below 2013 levels.

Changing the way we pay for gas

While the accuracy of the data is better than ever before, the estimates are still conservative because they are based on emissions factors and leak estimates, rather than direct measurements. And the emissions are likely to go up before they go down. That's because leak detection and quantification technology required under SB 1371 is better equipped at finding leaks – meaning utilities will start accounting for more leaks with each survey.

Based on an average wholesale market price of gas, these losses mean ratepayers are paying approximately $18 million every year for gas that is never delivered.

The issue of what to do about the value of lost gas – and the resulting incentives for additional leak reduction – will be an important conversation. SB 1371 asks the Commission to adjust the amount that utilities can charge customers based on actual leakage volumes, meaning the companies may no longer get paid for gas that leaks from their pipes before it's delivered to the customer.

Two utilities, two different strategies for reducing gas leaks

While the report reveals troublingly high emissions, we also know that California's two largest gas utilities, PG&E and SoCalGas, are committing to new efforts to reduce methane pollution. Their public filings, however, point to markedly different strategies.

PG&E has already begun implementing most of the practices proposed by CPUC as part of SB 1371. These include modern mobile leak detection equipment, faster leak survey, and a reorganized leak repair process to bundle and fix leaks faster and more efficiently.

In contrast, SoCalGas – the nation's largest gas utility, and the company responsible for the Aliso Canyon gas leak – appears to be dragging its feet. The utility argues against the practices recommended by CPUC and embraced by PG&E and other leading utilities, arguing that they are ineffective at finding and helping reduce lost gas.

These differences in utility commitment to reducing emissions may be softened by providing the public with an accurate and transparent report of emissions. Utilities will be more inclined to ensure their actions actually reduce emissions if they are held accountable by the public.

How better transparency can improve emissions reductions efforts

SB 1371 requires the Commission to provide the public with accurate information about the number and severity of gas leaks. The report aggregated the data of all the utilities and storage facilities but did not specify utility-specific statistics. The companies posted some of the data publicly on their websites only after requests by EDF, even though public transparency is required under the law.

Obscuring the origin of emissions is inconsistent with other air pollution and climate change reporting requirements at California Air Resource Board or the EPA. Air pollution data is public, and California ratepayers have a right to see a transparent evaluation of their utilities emissions profile. In the future, the CPUC should show total emissions for individual utilities more clearly, including labeling their share of leaks and emissions in each category.

Only by portraying emissions from individual utilities, instead of industry-wide aggregated data, will transparency requirements be satisfied. Public accountability will also help to ensure utilities stay motivated and continue to reduce their emissions. The Commission should not shy away from showing ratepayers which utilities are achieving the most gains. Not only will these steps give the public and utility ratepayers transparent analysis, it will ensure the utilities know which emissions to prioritize.

Image source: Max Pixel

California Air Resources Board and California Public Utilities Commission Joint Staff Report

Analysis of the Utilities' June 17, 2016, Methane Leak and Emissions Reports Required by SB 1371

SB 1371 (Leno). Natural Gas: Leakage Abatement

R.15-01-008

Ed Charkowicz, CPA, CPUC
Andrew Mrowka, P. E., ARB
Win Setiawan, ARB

January, 2017

January, 2017

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January, 2017

Executive Summary

On September 14, 2014, Governor Jerry Brown signed into law Senate Bill (SB) 1371, which requires gas corporations to report natural gas emissions from their facilities and summarize utility leak management practices, among other requirements.[1] In accordance with SB 1371, the California Air Resources Board (ARB) and California Public Utilities Commission (CPUC) prepared this report to analyze and account for natural gas emissions from leaks and vented emissions in the natural gas transmission, distribution and storage facilities in California.[2]

This is the second annual report in compliance with SB 1371 on natural gas emissions from utilities within the jurisdiction of the CPUC. The 2014 ARB and CPUC Joint Staff Report (the 2014 Joint Report) used 2014 data submitted by the utilities in May 2015 and was issued in February 2016. This Joint Staff Report (the 2015 Joint Report) uses 2015 data submitted by utilities on June 17, 2016, with additional data submitted in response to data requests from staff.[3]

On September 19, 2016, the Governor signed into law SB 1383 requiring "…the state board, the Public Utilities Commission, and the State Energy Resources Conservation and Development Commission to undertake various actions related to reducing short-lived climate pollutants in the state." SB 1383 directs ARB to "… approve and begin implementing the comprehensive short-lived climate pollutant strategy…to achieve a reduction in the statewide emissions of methane by 40 percent…below 2013 levels by 2030."[4] In addition, SB 32, which sets a 40% greenhouse gas reduction target for 2030, was passed and signed into law in 2016.[5] Both of these statutes build upon California's 2006 landmark policy, expressed in AB 32, for reducing greenhouse gas (GHG) emissions to 1990 levels by 2020.[6] This additional legislation directs ARB to develop plans to reduce statewide methane emissions. Although this legislation directs ARB to achieve certain methane and GHG reduction goals, neither statute has been explicitly scoped into a Phase 1 or Phase 2 of this proceeding.

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[1] PUC Code Section 975, Article 3 added by Stats. 2014, Ch. 525, Sec. 2. Effective January 1, 2015.

[2] Unless specified as a fugitive leak or vented emission, for the purposes of this report "emissions" include both fugitive leaks, and vented emissions of natural gas.

[3] R. 15-01-008, *Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371*

[4] *HSC - CHAPTER 4.2. Global Warming [39730 - 39731] (Chapter 4.2 added by Stats. 2014, Ch. 523, Sec. 1.) Sections 39730.5, 39730.6, 39730.7, and 39730.8.*
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

[5] California Global Warming Solutions Act of 2006: emissions limit. SB32, Pavley, Reg. Sess. 2015-2016. (2016).

[6] California Global Warming Solutions Act, AB32, Reg. Sess. 2005-2006 (2006)

January, 2017

This report provides the total estimated emissions from the gas storage and delivery systems and discusses emissions by system categories, by source categories and by leak grades.[7] This information should be used by gas system operators to help determine where emission reductions can be achieved to meet the State's methane emission reduction goal, while maintaining the safe and reliable operation of the regulated gas storage and delivery systems.

ARB's latest statewide GHG inventory, using 2014 data, reports California methane (CH4) emissions in 2014 were about 39.8 million metric tons of carbon dioxide equivalent (MMTCO2e), using the 100-year global warming potential (GWP) of methane (see Table ES-1) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4), comprising approximately 9% of the State's total GHG emissions.[8]

Based on the utilities' latest reports, the total natural gas emissions estimate is 6,601.2 million standard cubic feet (MMscf) in 2015.[9] Using the IPCC global warming potential (GWP) value of 25 (AR4, 100-year methane GWP), this equates to approximately 2.96 million metric tons of carbon dioxide equivalent (MMTCO2e) emissions. Or using the IPCC GWP AR4, 20-year methane GWP value of 72 the 2015 emission estimate equates to 8.51 MMTCO2e. The CH4 emissions from gas utility facilities in 2015 are about 7.5% of the statewide CH4 emissions documented in 2014.

Table ES-1: SB 1371 Sector Emissions for 2015 (without Aliso Canyon):

Million Standard Cubic Feet (MMscf)	**6,601.2**
100-year GWP (x25) Million Metric Tons CO2e[10]	2.956
20-year GWP (x72) Million Metric Tons CO2e[11]	8.512

[7] "System Category" refers to the grouping of assets by function within the natural gas delivery system. "Source Category" refers to grouping emissions based on like source, e.g. pipelines emissions, or M&R station emissions. See page 9 of this report for definition of leak grades.

[8] https://www.arb.ca.gov/cc/inventory/data/data.htm

[9] Note: This intentionally excludes the methane released from the 2015 Aliso Canyon storage failure because the extraordinary failure of the Aliso Canyon storage facility investigation and resultant regulations were handled outside this proceeding. The emissions from Aliso Canyon have been reviewed by ARB and the results are discussed in the Findings and Discussion section of this report.

[10] For purposes of this report we will use a GWP multiplier consistent with EPA and ARB which is 25 times the CO2e for methane. See calculation method in Appendix D.

[11] For comparison and context, we included the GWP consistent with ARB's methods that shows methane over a 20-year life cycle is 72 times more potent than CO2. See calculation method in Appendix D. Regardless of which GWP is used, the relative ratios of methane emissions from various components of the gas system remain consistent.

One of the key findings of this report is that graded leak emissions make up 22% of all reported emissions in 2015. The majority of emissions, 78% of the total, come from ungraded leaks and vented emissions (Figure 6).[12] In the 2014 data, graded leaks only accounted for 11% of emissions and ungraded leaks and vented emissions accounted for 89% of reported emissions in the gas delivery system.

Table ES-2: SB 1371 2015 Emissions by System Category:

System Categories	Category Total MMscf	%
Transmission Pipelines	549.2	8.3%
Transmission M&R Stations	1,007.2	15.3%
Transmission Compressor Stations	162.7	2.5%
Distribution Main & Service Pipelines	1,702.9	25.8%
Distribution M&R Stations	1,348.1	20.4%
Customer Meters	1,638.3	24.8%
Underground Storage (without Aliso Canyon)	192.8	2.9%
	6,601.2	100.0%

CPUC and ARB Staff (Staff) attribute the differences between 2014 and 2015 graded and ungraded leak volumes to the changes in the data requested in 2015, such as the inclusion of the estimated graded leaks in un-surveyed areas, as well as requiring consistent application of conservative emissions factors (EFs) for 2015. Because of the changes in the data request, direct and detailed comparisons between 2014 and 2015 are not practical.

For both the 2014 and 2015 Joint Reports, the Distribution Mains and Services pipeline leak volumes make up virtually all graded leak volumes.[13] In the current report, the Distribution Mains and Services leaks comprise 99.6% of emissions from graded leaks and Transmission Mains and Services Leaks make up the remaining 0.4%. Grade 1 leak volumes comprise 25% of the total, Grade 2 about 16%, and Grade 3 the remaining 59.0% (Figure 4 and Table 3).[14]

[12] Vented emissions include operational blowdowns, automatic pressure relief valves, and other venting done for safety or operational reasons.

[13] In 2015 the transmission pipeline leak volumes are included but only make up 0.4% of graded leaks and 0.08% of total emissions. See Lessons Learned item number 7, page 32 below.

[14] Grade 1 leaks are leaks that represent an existing or probable hazard to persons or property and require prompt action. Grade 2 leaks are leaks that are not hazardous at the time of detection but justify a scheduled repair based on potential for a future hazard. Grade 3 leaks are leaks that are not hazardous at the time of detection and can reasonably be expected to remain non-hazardous.

For the 2015 Joint Report, utilities estimated the proportion of graded leaks that occur between surveys in the un-surveyed portions of their service territory based on the leak occurrence rate. As such, 46% of the graded leaks are estimated to exist in the un-surveyed areas (Figure 4 and Table 3) made up of approximately 660 MMscf, and this comprises 10% of the total emissions reported.

The ungraded leaks and vented emissions (78% of the total natural gas emissions) comprise the following system categories (Figure 2):

- Metering and Regulation (M&R) stations (both transmission and distribution) 35.7% of the total,
- Customer Meters 24.8%,
- Ungraded Pipeline emissions (both transmission and distribution) 11.9%,
- Compressor stations 2.5%, and
- Underground Storage facilities (excluding Alison Canyon) 2.9%.

Figure 6 shows emissions by activity category.[15] All blowdown and venting associated with operations and maintenance activities when grouped together account for 9.2% of emissions. Pipeline damages accounts for 4.8% of the total. Storage leaks and emissions (excluding the Aliso Canyon event) make up 0.8% and are combined with the ungraded leaks from M&R, Compressor, and Odorizer stations and their associated component leaks as well as Customer meter set assemblies (MSAs) that contribute 64.8% of the total natural gas emissions. This grouping highlights potential areas to focus on for improving practices, equipment or detection methods.

Conclusion:

The report describes a framework for understanding the data submitted in the June 17, 2016, reports and subsequent resubmittals. Some of the major findings are:

- The baseline emissions estimate for 2015 from SB 1371 sector utilities totals 6,601.2 MMscf, equal to 2.96 MMTCO2e using the AR4 100-year methane GWP or8.51 MMTCO2e using AR4 20-year methane GWP, which provides a starting point to measure future natural gas emission reductions.
- Significant changes to emission factors (EFs) could occur based on improved information. Staff would need to consider the implications of the change and potential need to adjust the baseline to avoid incorrect accounting. Nevertheless, the categories with the highest emission levels should be the

[15] For the Figure 6 chart the blowdowns and venting in each system category were grouped together, likewise pipeline damages were grouped together, and all ungraded leaks and emissions in the M&R, Compressor, and Odorizer stations.

starting point for establishing best practices to achieve the greatest amount of reductions for resources expended.

- The vast majority of ungraded emissions (64%, Figure 6) come from the components and equipment found throughout the delivery system. By parsing the emissions and identifying the volume of emissions and their sources, utilities can focus on the most cost-effective means to reduce emissions. By using actual emissions data, utilities should be able to address operating and maintenance practices, and component designs and materials to facilitate emission reductions.
- Among leaks that have been categorized as potential hazards, the grade 3 leaks make up a significant amount of leaks that are carried over year after year, making up 59% of the volume of all graded leaks. Even though grade 3 leaks are not considered a safety threat, cost-effective ways should be found to fix them sooner to reduce this persistent source of emissions.
- About 10% of the total emissions were from graded leaks in un-surveyed areas, estimated to occur between leak survey cycles. By reducing leak survey cycle times, the leaks occurring between cycles will emit for shorter lengths of time until they are detected and repaired. This effort should reduce emissions from graded leaks.
- Use of EFs may be acceptable in the short term for establishing the baseline emission levels. However, in order to better quantify emission reductions over time utilities must devise better ways to measure actual leak volumes. Relying on EFs may not fully account for emissions and reductions over time (e.g. every leak fixed is assumed to be emitting the same amount). Because it is difficult to quantify the actual volume of leaks and emissions, more work is needed to develop and improve California specific EFs until actual emissions measurements are available for the sources where it is feasible to directly measure emissions.
- Continuing refinement and improvement of the data reporting templates should increase transparency, and provide formats that consistently capture reliable leak and emission data for measuring changes in natural gas emissions.

Introduction

In accordance with Senate Bill (SB) 1371, the California Air Resources Board (ARB) and California Public Utilities Commission (CPUC) prepared this report to analyze and account for methane from leaks and vented emissions in the natural gas transmission, distribution and storage units in California.[16] On September 14, 2014, Governor Jerry Brown signed into law SB 1371, which required reporting and verification of emissions of greenhouse gases and also required gas corporations to file a report summarizing utility leak management practices, a list of new methane leaks by grade, a list of open leaks that are being monitored or are scheduled to be repaired, and a best estimate of gas loss due to leaks.

The report quantifies the emissions reported from the gas storage and delivery systems as well as shows those emissions by system categories, source categories and by grade. The information should be used by the gas system operators to help determine where emission reductions can be achieved while maintaining the safe and reliable operation of commission-regulated gas pipelines and other facilities. The metrics being used to compile this report should provide operators, the Commission, and the public with reasonably accurate information about the type, number, and severity of emissions and about the quantity of gas emitted to the atmosphere over time.

Additionally, on September 19, 2016, the Governor signed into law SB 1383 requiring "the state board, the Public Utilities Commission, and the State Energy Resources Conservation and Development Commission to undertake various actions related to reducing short-lived climate pollutants in the state." [17] The State Board (ARB) "shall approve and begin implementing the comprehensive short-lived climate pollutant strategy developed pursuant to Section 39730 to achieve a reduction in the statewide emissions of methane by 40 percent… below 2013 levels by 2030."

SB 1383 strengthens the work initiated by SB 1371 and focuses on the coordination between state and local agencies to develop measures for evaluating the progress of gas emission reductions. SB 1383 "… would require the state board *[Air Resources Board]*, no later than January 1, 2018, to approve and begin implementing that comprehensive strategy to reduce emissions of short-lived climate pollutants to achieve a reduction in methane by 40%, below 2013 levels by 2030. …"

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[16] Unless specified as a fugitive leak or vented emission, for the purposes of this report "emissions" include both fugitive leaks, and vented emissions of natural gas.

[17] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

In addition, SB 32, which sets a 40% greenhouse gas reduction target for 2030, was passed and signed into law in 2016.[18] Both of these statutes build upon California's 2006 landmark policy, expressed in AB 32, for reducing greenhouse gas (GHG) emissions to 1990 levels by 2020.[19] This additional legislation directs ARB to develop plans to reduce statewide methane emissions. Although this legislation directs ARB to achieve certain methane and GHG reduction goals, neither statute has been explicitly scoped into a Phase 1 or Phase 2 of this proceeding.

Background

According to the Intergovernmental Panel on Climate Change (IPCC) fourth Assessment Report (AR4), methane is 72 times more potent a greenhouse gas (GHG) than carbon dioxide (CO2) over a 20-year time frame. Although the more recent fifth Assessment Report (AR5) estimates a Global Warming Potential (GWP) multiplier as high as 86 times the impact of CO2 over a 20-year span, the AR4 values are used for consistency. ARB and EPA also use an alternate method for estimating methane emissions based on the AR4 for reporting GHG inventory levels that assumes an impact time frame over a 100-year span that results in a GWP factor of 25.[20] Many climate change researchers claim that using the 100-year time frame significantly understates the near-term impact of potent GHGs like methane. At this time, ARB uses the 100-year GWP for its official reporting of GHG inventories but uses the 20-year GWP for short lived climate pollutants such as methane. Both the 100-and 20-year GWP will be shown in this report.

ARB Staff analyzed sources of methane emissions as part of the annual Greenhouse Gas Inventory and the draft Short Lived Climate Pollutant (SLCP) Reduction Strategy. The chart below shows 2014 methane emissions from the transmission and distribution sector (i.e. pipelines) accounted for approximately 9% of total methane emissions in California. Using the 100-year methane GWP shown in the chart methane emissions are about 9% of the total GHG emissions in the state[21]; with methane emissions from the natural gas transmission and distribution systems making up 7.5% of 9%, or about 0.7% of California's total GHG emissions. Using the 20-year

[18] California Global Warming Solutions Act of 2006: emissions limit. SB32, Pavley, Reg. Sess. 2015-2016. (2016).

[19] California Global Warming Solutions Act, AB32, Reg. Sess. 2005-2006 (2006).

[20] ARB used the AR4 100-year value of 25 times the CO2e for methane in its accounting for the 2000-2014 GHG inventories. See https://www.arb.ca.gov/cc/inventory/background/gwp.htm

[21] The 2014 GHG inventory shows 441.5 metric tons of CO2e and of that 39.8 metric tons of CO2e come from Methane or 9% of California's GHG in 2014 (39.8mtCO2e/441.5mtCO2e = 0.09 or 9%).

methane GWP increases the natural gas transmission and distribution systems contribution to statewide GHG to 1.7%.[22]

Purpose of the Gas Leak Abatement Report

This report provides a summary of the 2015 emissions inventory reports submitted by the utility companies on June 17, 2016. In order to meet the State's greenhouse gas reduction targets, California needs a current picture of methane leaks and emissions.[23]

The Administrative Law Judge (ALJ) ruling, *Entering Newly Revised Natural Gas Leak Annual Reporting Requirements into the Record and Seeking Comments*, issued on January 26, 2016, proposed using 2015 as the baseline year for natural gas emissions.[24] The CPUC received comments from the parties through February 24, 2016, and for the most part parties did not object to using 2015 as the baseline year. It is with this common understanding that the 2015 estimated methane leaks and emissions (sans extraordinary events such as Aliso Canyon) are at approximately the same level of emissions that occurred in 1990.[25]

Starting from this premise, the 2015 reported emissions provide a reasonable and reliable baseline to gauge reduction efforts going forward.

On April 12, 2016, the CPUC Staff issued a data request to all utilities in California to collect the information required by Article 3, Section 975 (c) and (e)(6). The data requests were developed to meet the requirements of Article 3, Section 975 (c) (1 through 4) and (e)(6). (See Appendix C for detailed wording.)

Pipeline leaks are categorized according to their "grade."

- Grade 1 leaks are leaks that represent an existing or probable hazard to persons or property and require prompt action.[26]
- Grade 2 leaks are leaks that are not hazardous at the time of detection but justify a scheduled repair based on potential for a future hazard.

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[22] Using the 20-year methane GWP increases the methane component of California GHG inventory to 113.7 MMTCO2e, added in place of the 39.8 MMTCO2e gives an estimated total of 515.4 MMTCO2e GHG for California. The natural gas transmission and distribution 20-year methane GWP of 8.512 MMTCO2e is 1.7% of 515.4 MMTCO2e.

[23] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB 1371: SB 1371 refers to the AB 32 requirement to reduce California emissions to 1990 levels by 2020.

[24] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K902/157902581.PDF

[25] California emissions of GHGs fell during the economic downturn from 2008 through 2012 and have not rebounded back to levels before the downturn.

[26] If a leak has not been graded but has been labeled Hazardous it will be included with the Grade 1 totals.

- Grade 3 leaks are leaks that are not hazardous at the time of detection and can reasonably be expected to remain non-hazardous.[27]
- Any remaining leaks are classified as ungraded leaks, such as leaks at customer meters and storage facilities.

Even though the system categories of emissions remained largely the same as those in 2014, a greater effort was made to standardize the data submissions to improve consistency and integrity of the data. To that end, the data request recommended the use of standard emissions factors (EFs) for this year's report.[28] The 2015 Joint Report covers emissions and leaks for associated components within system categories. Additionally, the report includes general discussions of changes to operational practices, new methods for leak and emission detection and mitigation programs. Lastly, improvements to data capture and methodology for estimating leaks and emissions may provide greater accuracy in future reporting cycles.

Basis for the Annual Gas Leak Abatement Report:

The data obtained for this report were provided by the natural gas operators including the large and small gas utilities (utilities), and independent storage providers (ISPs). The data were separated into seven system categories:

1. Transmission Pipelines (leaks, damages, blowdowns, components, and odorizers),
2. Transmission Metering and Regulation (M&R) stations (leaks, blowdowns, and components),
3. Compressor stations (compressor leaks and emissions, blowdowns, components, and storage tanks),
4. Distribution Pipeline Mains and Services (leaks, damages, blowdowns, and components),
5. Distribution M&R stations (leaks and emissions, and blowdowns),
6. Customer Meters (leaks, and venting), and
7. Underground Storage Facilities (leaks, compressors leaks and emissions, blowdowns, components, and dehydrators).

The respondents provided contextual information and explanations for their data to help understand the composition of the emissions, emission sources and related calculations underlying the emission estimates. The respondents summarized the data

[27] If a leak has not been graded but has been labeled Non-hazardous it will be included in Grade 3 totals.
[28] See Appendix 9 of the Data Request for specific EF's recommended by each System Category. http://www.cpuc.ca.gov/General.aspx?id=8829

and provided their system-wide leak information. See Appendix A for explanation of methods used to estimate emissions.

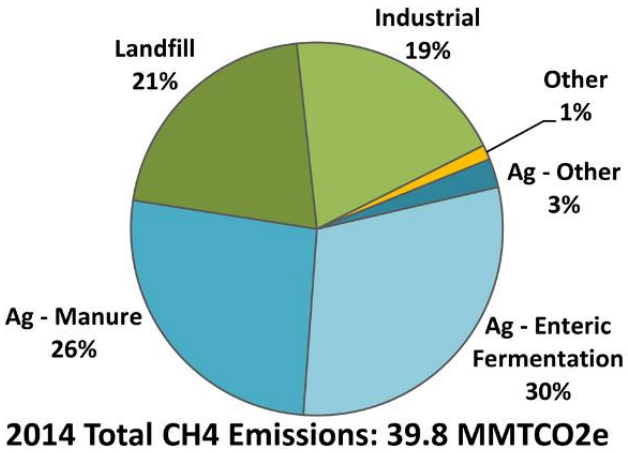
ARB and CPUC Staff worked together to prepare the templates used to report the data requested for the 2015 Joint Report. The templates were developed through working groups and feedback from parties on the data to be requested and how it should be structured in the template. The templates establish consistency in the data reporting and serve to highlight differences between data from different respondents.

ARB and CPUC Staff jointly analyzed the data for integrity and consistency. To complete the analysis, Staff requested supplementary information for clarification and submission of subsets of the data as issues were identified and corrected. Staff acquired insights and identified potential improvements through this process and noted opportunities for enhancements in future data requests in the "Lessons Learned" section of the report. Staff expects further evolution and improvement of emissions estimation methods going forward, as well as improved actual measurements.

Many of the improvements in the 2015 data request and emission estimating methods used render the 2014 data not directly comparable to the data collected in 2015. However, in the future it may be possible to apply improved estimation methods to previous year's estimates for like categories.

Findings and Discussion

Figure 1: The Latest Data on California Methane Emission Sources - 39.8 MMTCO2e Emissions in 2014:[29]



Ongoing Systemic Leaks and Emissions:

[29] https://www.arb.ca.gov/cc/inventory/background/ch4.htm

ARB's latest reported emission figures for 2014 (Figure 1) show that California is responsible for 441.5 million metric tons' carbon dioxide equivalent (MMTCO2e) GHG emissions.[30] Of this, the CH4 emissions comprise 9% or 39.8 MMTCO2e of California Statewide emissions. Staff does not have 2015 statewide total GHG data at this time, but assume 2015 emissions are roughly consistent with 2014.

The 2015 estimated natural gas emissions of 6,601.2 MMscf, which equates to 2.96 MMTCO2e emissions (AR4, 100-year methane life cycle) represent 0.67% of 2014 statewide GHG emissions and 7.5% of 2014 methane emissions.[31]

Methane is recognized as a very potent GHG, which has an impact many times greater than carbon dioxide (CO2). Using AR4's 20-year methane life cycle for the 2015 emission estimate would equate to 8.51 MMTCO2e.

ARB's SLCP reduction strategy concludes that California can reduce its methane emissions by 40 percent below current levels through a collaborative and mixed approach that combines incentives, public and private investment, and regulation.[32]

The 2015 reported emissions totaled 6,601.2 MMscf, whereas the 2014 reported emissions totaled 3,880.7 MMscf. Though this initially might lead one to believe a 70% increase in natural gas emissions took place year over year, the difference can be partially explained by changes made as a result of changes to 2015's data request resulting from lessons learned from the 2014 report. There are several reasons why the 2015 data are not comparable to 2014 data:

1) The 2014 Distribution Mains and Services pipeline leaks included all detected leaks including above ground leaks that may have been associated with customer meter set assemblies (MSAs). The 2015 data excluded any above ground leak considered to be part of the MSA.
2) Because pipeline leak surveys are done on multi-year cycles, for 2015 pipeline operators made a significant effort to estimate the leaking potential from the leaks that occur between surveys in un-surveyed territory.
3) The 2015 templates recommended specific EFs to ensure consistency between operator data; whereas in 2014 operators were allowed greater latitude in the EFs each could use and justify.
4) Greater rigor was imposed on the calculation of emissions from blowdowns, components and equipment.

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[30] https://www.arb.ca.gov/cc/inventory/data/data.htm

[31] Total Natural Gas emissions reported to the CPUC/ARB for the 2015 annual report without Aliso Canyon come to 6,601.2MMscf which translates to 118,228 metric tons of methane. See Appendix D for calculations.

[32] https://www.arb.ca.gov/cc/shortlived/shortlived.htm

5) The categorization in the 2015 data templates differs significantly from 2014's. As a result, comparing 2015 reported data to 2014 may result in misleading or invalid conclusions about the trend or changes in emissions.

Aliso Canyon Storage Facility:

Beginning in October 2015 and lasting through February 2016, operators of the Aliso Canyon gas storage facility in Southern California reported an uncontrolled leak preliminarily attributed to the failure of well pipe casing below ground level. The root cause analysis is still ongoing. Based on ARB analysis, the Aliso Canyon leak event contributed about 5% to California's State wide natural gas emissions in 2015.[33] The ARB study used various measurement and quantification methods to evaluate the range of estimates that converged around a total quantity of 99,650 metric tons of methane emissions for the duration of the leak.[34]

The duration of the event and difficulty to contain the large storage leak raised the national awareness of the risks associated with natural gas storage facilities. Consequently, this large leak resulted in new storage facility regulations and a new awareness of the significant impact that storage facilities have on California electric generation and consumers of natural gas in southern California. The environmental risks from this single leak were substantial and the safety, operations and maintenance regulations are still under examination.

For purposes of this report, Staff focused on the leaks and emissions from ongoing operations. The catastrophic nature of Aliso Canyon emissions will be discussed in context, but they are largely outside the scope of this report and the efforts to reduce systemic emissions in this sector.

Key Findings:

A key finding from 2015 data is that although the graded leaks are significant, the ungraded leaks and associated emissions make up the largest subset of emissions reported. The ungraded leaks and vented emissions comprised 3.5 times the amount as the graded leaks at 78% of the total system emissions from the gas delivery system (Shown in Table 2).

In 2014, Staff reported that graded leaks were about 11% of the emission volume and ungraded leaks and emissions were approximately 89%. In 2015, the magnitude of

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[33] The 78,895 MT of CH4 equated to 1.97 MM MT CO2e or 4.7% of estimated 2015 CH4 emissions assuming 2014 and 2015 CH4 overall emissions would be the same. Calculated emissions based on ARB report page 25 data. https://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_methane_emissions-arb_final.pdf

[34] Ibid, Pg.1.

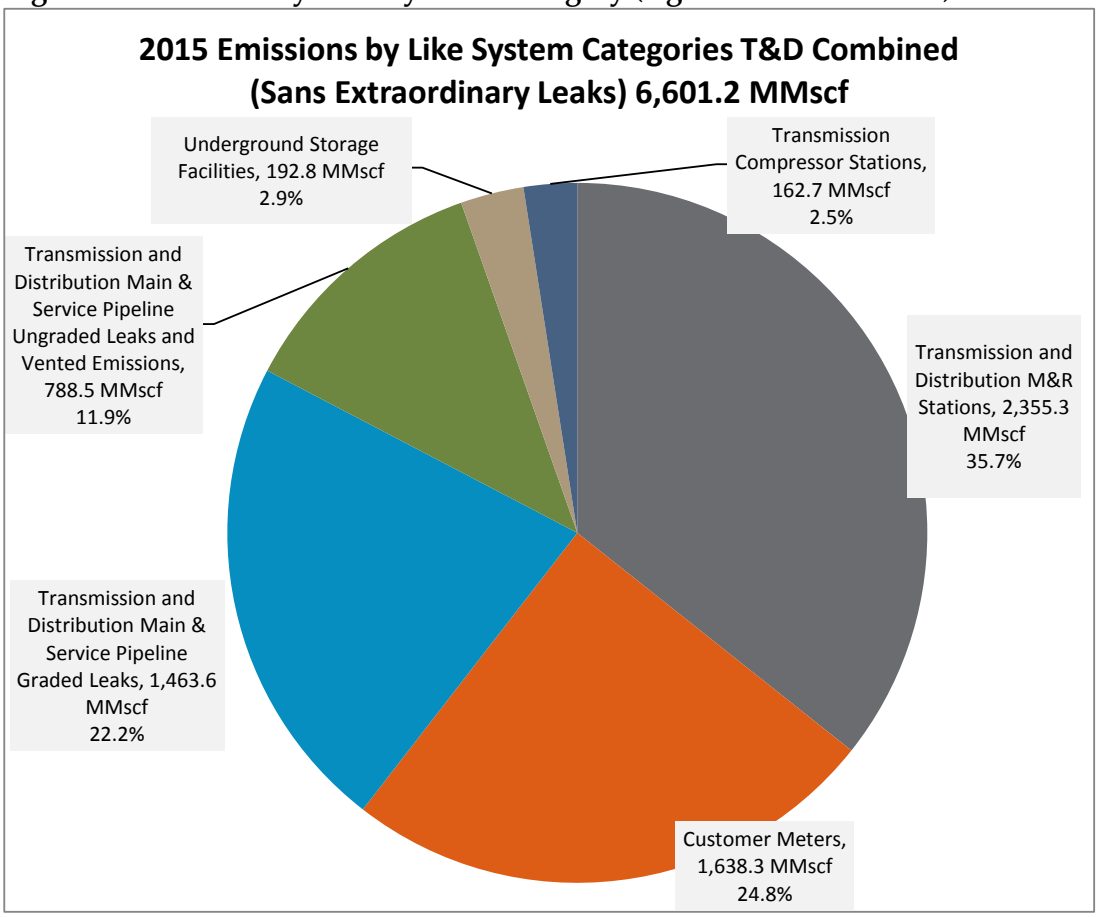
the difference appears to be significantly less, which Staff attribute to several changes to the data provided year over year as noted above.

The graded leaks volume makes up 22% and almost exclusively represents Distribution pipeline leak volumes.[35] As noted in the prior section, the changes in the data request make detailed comparisons between 2014 and 2015 difficult. The ungraded leaks and vented emissions that make up the remaining 78% of the total (see Figure 2) are listed below by system category:

1. M&R stations (both transmission 15.3% and distribution 20.4% combined), 35.7%,
2. Customer meter set assemblies (MSAs), 24.8%,
3. Ungraded leaks and vented emissions in the combined Transmission (8.2%) and Distribution (3.7%) pipeline systems, 11.9% (omitting the 22.2% for graded leaks),
4. Compressor stations, 2.5%, and
5. Underground Storage facilities (sans Alison Canyon) 2.9%.

[35] Transmission pipeline leak volumes are included but only make up 0.04%.

Figure 2: Emissions by Like Systems Category (e.g. All M&R stations.):[36]



In Figure 2, both the Transmission and Distribution Pipelines data were combined, graded leaks were combined and the remaining emissions from the pipeline system categories were also combined to differentiate the emissions from pipeline components, damages, and other sources other than pipeline graded leaks.

The potential for mitigation of emissions from facilities and components becomes apparent because it comprises nearly two thirds of the sector emissions. Venting and blowdown emissions are approximately 9% of the total, and though this is significant, it by itself would not provide enough reduction opportunity to achieve the reduction goals needed to meet the levels required by SB 1371 and SB 1383.

Additionally, by separating out and combining the emissions by the source activity, such as all blowdowns together, or station facilities, or compressors no matter

[36] For this chart the compressors from underground storage, compressor stations and their related components were grouped together. The underground storage facility emissions represent the grouping of the underground storage facility, components and dehydrators. Any venting or blowdowns from all facilities were grouped into the Blowdown and Venting total.

where located, it is easier to see emissions from like activities and systems. This is discussed further and shown in Figure 6 later in the report.

Global Warming Potential – Putting the Emissions into Context:

Table 1 shows the total emissions reported (excluding the Aliso Canyon Storage leak) for ungraded leaks and vented emissions, and pipeline graded leaks in MMscf of natural gas, metric tons of CH4 as well as for both the 100- and 20-year GWP values.

Table 1: The Global Warming Potential in Various Equivalent Metrics:[37]

	MMscf	Metric Tons CH4	100 Year GWP MMTCO2e	20 Year GWP MMTCO2e
Ungraded Leaks and Vented Emissions	5,137.5	92,013	2.300	6.625
Pipeline Graded Leaks	1,463.6	26,214	0.655	1.887
2015 Total Emissions	**6,601.2**	**118,226**	**2.955**	**8.512**

The total emissions equate to 285,000 trips driven around the world at the equator, which would burn about 332.6 million gallons of gasoline.[38] See Appendix D for details on how the GWP was calculated.

Emissions by System Category:

As required by SB 1371, each utility company was asked to provide information for the seven appendices: (1) Transmission Pipelines, (2) Transmission M&R Stations, (3) Transmission Compressor Stations (4) Distribution Mains and Services Pipelines, (5) Distribution M&R Stations, (6) Customer Meters, and (7) Underground Storage.

All ten natural gas utilities jurisdictional to the CPUC responded to the data request. Each utility reported emissions from more than one appendix. This report will avoid identifying individual companies' data responses, but will report data in aggregate. The companies will collectively be identified as "utilities." The findings for each appendix are discussed following the Figure 3.

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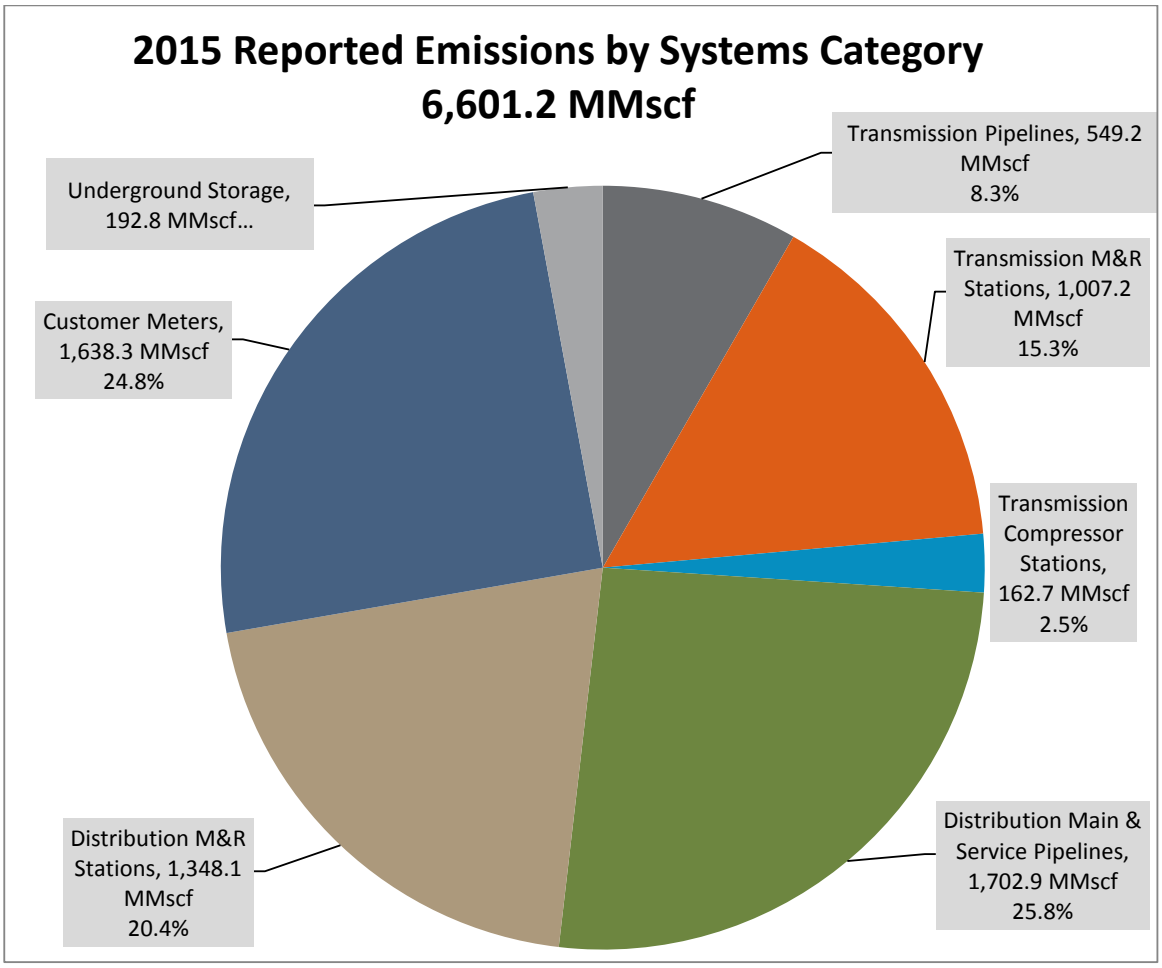
[37] EPA GHG equivalency calculator derived amounts (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator) using a 100-year GWP multiplier of 25.

[38] EPA's GHG calculator shows that 118,226 mtCO2e equates to 332.6mm gallons of gasoline, or 7,083mm miles driven by the average car. Dividing the 7,083mm miles by the circumference of the earth at the equator (24,901miles) the result is 284,474 trips around the globe. https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm

Figure 3: Reported Emissions by System Category:[39]



Transmission Pipeline

Four utilities reported a total of transmission pipeline emissions of 549 MMscf or 8% of the total. The major contributor to emissions in this category comes from blowdowns of approximately 455 MMscf of natural gas; while pipeline leaks only approximated 5 MMscf. Damages from third parties came to 82 MMscf, associated components emitted 5 MMscf, and odorizers emitted 3 MMscf. Transmission pipeline survey cycles vary from one to five years depending on the type, location and condition of the pipeline.

[39] Each system category includes all the associated leaks and vented emissions from its related infrastructure, such as leaks, component leaks, vented emissions and damages.

Transmission M&R Stations

Four utilities reported total transmission M&R stations emissions of 1,007 MMscf or 15% of the total. This category includes farm taps, transmission inter-connects and intra-connects. The emissions from M&R stations leaks approximated 942 MMscf, blowdowns were 66 MMscf, and associated components added 0.02 MMscf.

Transmission Compressor Stations

Three utilities reported total transmission compressor stations emissions of 163 MMscf or 3% of the total. The majority of emissions of 106 MMscf came from the compressors, blowdowns were 31 MMscf and leaks from associated components were 25 MMscf. The storage tank leaks and emissions amounted to 0.003 MMscf.

Distribution Mains and Services

Six utilities reported total distribution mains and services emissions totaling 1,703 MMscf or 26% of total emissions. This asset category comprised the single largest system category of natural gas emissions. The smaller utilities perform leak surveys annually, whereas the larger utilities perform leak surveys of their service territory over multiple years[40]. After the initial data reports were submitted, Staff discussed the data submissions with utilities and found differences in methods used to estimate leaks in un-surveyed portions of utility territory. The CPUC and ARB worked with utilities to standardize the methodology of calculating emissions from un-surveyed mains and services.[41] The methodology will be reviewed in future workshops and memorialized in future data requests.

Distribution mains and services pipeline graded leaks came to 1,458 MMscf, damages by third parties accounted for 236 MMscf, blowdowns at 5 MMscf and associated component emissions came to 3 MMscf.

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[40] The utilities perform periodic surveys with different cycles depending on the type of infrastructure, statutory requirements and regulations and operating practices. Cycles of one, three and five years are common.

[41] The basic approach used takes the leak occurrence rate and estimates the leaks that occur in the sections of service territory since the last survey. For example, if the survey cycle is three years and the leak occurrence rate is 3, then the expectation is that in the section of territory surveyed in the prior year 33% the number of leaks occurred, and in the section surveyed two years' prior 67% the number of leaks occurred. So, these added together would net 100% or a factor of 1 times the number of leaks occurring added to the leaks found in the year of interest to estimate the system leaks.

Distribution M&R Stations

Four utilities reported total distribution M&R station emissions of 1,348 MMscf or 20% of total reported emissions. The M&R station blowdowns were quite small at 0.3 MMscf.

Customer Meters

Six utilities reported emissions from MSAs totaling 1,636 MMscf, which is virtually this entire system category's total of 1,638 MMscf or about 25% of total emissions. The emissions from MSAs are based on EFs applied to the population of customer meters. The venting associated with MSAs was estimated at 2 MMscf. MSA emissions are the second largest source of emissions.

Underground Storage

Six utilities reported underground storage systems emissions totaling 193 MMscf or 3% of the total (sans Aliso Canyon). The emissions from compressors used in this system category constituted the largest source of emissions at 96 MMscf, the associated storage facility leaks come to 15 MMscf, the blowdowns in this category are 46 MMscf, the dehydrators emit 20 MMscf, and other associated components emit the remaining 15 MMscf.

January, 2017

Table 2: Emissions Details by Category

System Categories	Category Total	%	Emission Source Categories SOURCE	Volume	%
Transmission Pipelines	549,248	8.3%	**Pipeline Leaks**	**5,237.6**	0.1%
			All Damages	**81,793.0**	1.2%
			Blowdowns	**455,055.5**	6.9%
			Component Emissions	**4,591.8**	0.1%
			Odorizers	**2,570.4**	0.0%
Transmission M&R Stations	1,007,226	15.3%	**Station Leaks & Emissions**	**941,622.0**	14.3%
			Blowdowns	**65,582.5**	1.0%
			Component Leaks & Emissions	**21.0**	0.0%
Transmission Compressor Stations	162,686	2.5%	**Compressor Emissions**	**106,257.2**	1.6%
			Blowdowns	**31,087.7**	0.5%
			Component Leaks & Emissions	**25,338.3**	0.4%
			Storage Tank Leaks & Emissions	**3.3**	0.0%
Distribution Main & Service Pipelines	1,702,871	25.8%	**Pipeline Leaks**	**1,458,398.6**	22.1%
			All Damages	**236,145.2**	3.6%
			Blowdowns	**5,045.6**	0.1%
			Component Emissions	**3,281.2**	0.0%
Distribution M&R Stations	1,348,067	20.4%	**Station Leaks & Emissions**	**1,347,772.5**	20.4%
			Blowdowns	**294.9**	0.0%
			Component Leaks & Emissions	**-**	0.0%
Customer Meters	1,638,274	24.8%	**Meter Leaks**	**1,635,910.4**	24.8%
			Vented Emissions	**2,363.4**	0.0%
Underground Storage	192,797	2.9%	**Storage Leaks & Emissions**	**15,016.4**	0.2%
			Compressor Emissions	**96,313.1**	1.5%
			Blowdowns	**46,358.0**	0.7%
			Component Leaks & Emissions	**14,946.6**	0.2%
			Dehydrator Vent Emissions	**20,162.9**	0.3%
	6,601,169	100%		6,601,169.0	100.0%

Specific Data Request Information

As required by SB 1371, each utility company was asked to provide information on the following activities: (1) leak management practices, (2) new methane leaks by grade, (3) open leaks that are being monitored or are scheduled to be repaired, (4) a best estimate of gas loss due to leaks and (5) a baseline system-wide leak rate.

Ten natural gas utilities submitted responses to the data request of which transport, distribute and/or provide natural gas storage services.

(1) Leak Management Practices:

Operator Changes to Identify, Report and Reduce Emissions – Question 1:

Each utility has a policy and an inspection plan to investigate leaks. All the California gas companies participating in this initiative utilize standard industry practices for leak detection and repair. Utilities also noted using novel practices and newer technologies. Some examples of different practices include the use of mobile mounted methane technology to assist in leak detection, while other utilities conduct walking gas leak surveys of their pipeline infrastructure, and some survey their right-of-way using flame ionization leak detection devices. Most operators utilize a combination of equipment, including flame ionization, remote methane leak detection, and amplified catalytic sensor devices, to search for the presence of natural gas leaks. One operator also utilizes the newer infrared based leak detection survey instruments process, as well as the standard hydrogen flame ionization detectors.

The gas utilities started examining and evolving practices and procedures for safety reasons prior to 2014 and the use of new leak detection technologies resulted in a significant increase in leaks detected and graded.

Utility operators expanded their use of technology to detect ambient leaks in their systems, though in varying degrees and types of technology. The use of mobile detection equipment increased and in one case there was a two-fold increase in distribution services surveyed in 2015 from 2014, and in 2015 operators expanded the use of analytical tools that focus on customer usage variables associated with the increased potential for leaks.

Automated use of database analytics, which detect unusual or aberrant gas consumption patterns, may provide a method for early detection that could significantly reduce the duration of a large leak. In addition, operators continued to evaluate and fund research on mobile leak quantification technologies (e.g. Picarro, Washington State University, Colorado State University, and other collaborative projects).

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Operators implemented the U.S. Environmental Protection Agency's (EPA) new Mandatory Reporting Requirements (MRR), which lowered the volume threshold for reporting blowdown events to those with volume of 50 cubic feet or greater. Related to operations and maintenance, where feasible, operators focused their efforts to reduce pipeline pressures prior maintenance procedures that reduce the volumes subject to venting or blowdown. In some cases, operators employed analytics to identify business districts that should be surveyed more frequently, in these cases higher risk areas are being surveyed more frequently with the potential for reduced safety risks as well as quicker identification and mitigation of leaks.

Due to the increased focus on best practices operators have unilaterally begun networking with experts across the nation to find better maintenance and mitigation procedures as well as share their own successes and experience with leak detection and mitigation. One operator reported voluntarily adopting EPA Gas STAR Rod Packing Replacement that is intended to reduce natural gas leakage from rod packings.

Additionally, the operator worked on improving operating procedures and simulated Emergency Shutdown (ESD) procedures to train operators and increase awareness and preparedness for ESD events. In other cases, where operation practices and human factors lead to inadvertent or excessive emissions in the past, utilities focused on changing procedures and increasing training over proper O&M procedures. In addition, third-party owned leak-prone compressors were removed and replaced with equipment less prone to emissions.

Lastly, operators continue to replace distribution mains and service pipeline in accordance with their operations and maintenance plans approved through the general rate cases that fund capital and maintenance investments.

Summary of Proposed Changes to Management Practices – Data Request Question 7.a:

The utilities' 2016 reports show a significant amount of changes to practices, equipment and research. The following brief summary of the intended and proposed changes to management and operating practices shows the potential for significant impact on natural gas emission reductions.

The summary includes the most significant changes outlined by respondents in their annual report filing. Many of the changes indicated a need for funding in order to undertake the proposed practice, or expand it beyond the pilot or research stage. The funding mechanisms and focus on what may be incremental funding for what many might characterize as the normal evolution of business and operating best practices is

beyond the scope of this report. Therefore, Staff excludes any reference to funding and focus only on the practice changes listed by respondents.

The items listed were noted by one or more of the utilities. Staff tried to include representative and significant changes in this list and does not include every proposed or initiated change reported by respondents.

1) Refine EFs to improve quantification of leaks and emissions on a granular equipment and component level that is below the macro facility EFs currently used for Customer Meter Set Assemblies, Direct Sale Meter Sets, M&R Stations, and Farm Taps. The current EFs are suspected of understating emissions, moreover, granular component specific EFs should improve quantification efforts and the studies should identify the leakiest components for targeting for reduction opportunities.
2) Reduce hazardous and non-hazardous leak inventories through shortened repair time protocols, and shortened survey cycles.
3) Identify pipeline segments most in need of replacement through GIS tools that facilitate prioritization and optimization of pipeline replacement programs by identifying leak clusters.
4) Increase the amount of annual distribution pipe replaced, focusing on pre-1940 steel and pre-1985 Aldyl-A pipe.
5) Increase commitment and participation in EPA's Methane Challenge to adopted best practices. Areas of impact include but may not be limited to: Excavation damages best management practice (BMP) through the Gold shovel program, and blowdown reductions through re-routing natural gas and flaring.
6) Continue research, evaluation and improvement of Mobile Methane Mapping Assessment of pipeline emissions to identify and prioritize pipeline for replacement results in emissions reductions.
7) Evaluate and Change O&M practices on compressors, e.g. to perform compressor rod packing replacements on more frequent operational intervals, and to evaluate compressor operating procedures that lead to reduced blowdowns during start up.
8) Change or replace high or intermittent bleed pneumatic devices with technology that vents less natural gas.
9) Improve data collection of blowdown activities that support better operational practices. Improve the type and breadth of data collected that may be used to examine current practices in order to streamline the information capture of blowdown and operational activities.

10) Adopt technologies that will allow the electronic tracking of verified gas leaks to facilitate electronic record keeping, with the potential to evolve into automated field readings updates, and provide mapping tools that overlays survey routes on existing infrastructure.
11) Implement site inspections per new Department of Geothermal, Gas and Oil (DOGGR) and ARB rules affecting Storage facilities. In addition, some utilities are going further by proactively identify and mitigate potential storage well safety and/or integrity issues to enhance their existing maintenance and prevention programs.
12) Conduct various research projects to advance the science and tools available to detect and quickly quantify leaks. For example, projects included fast accurate low detection level portable handheld instruments, leak survey tracking, and drone technology for detection and assessments.

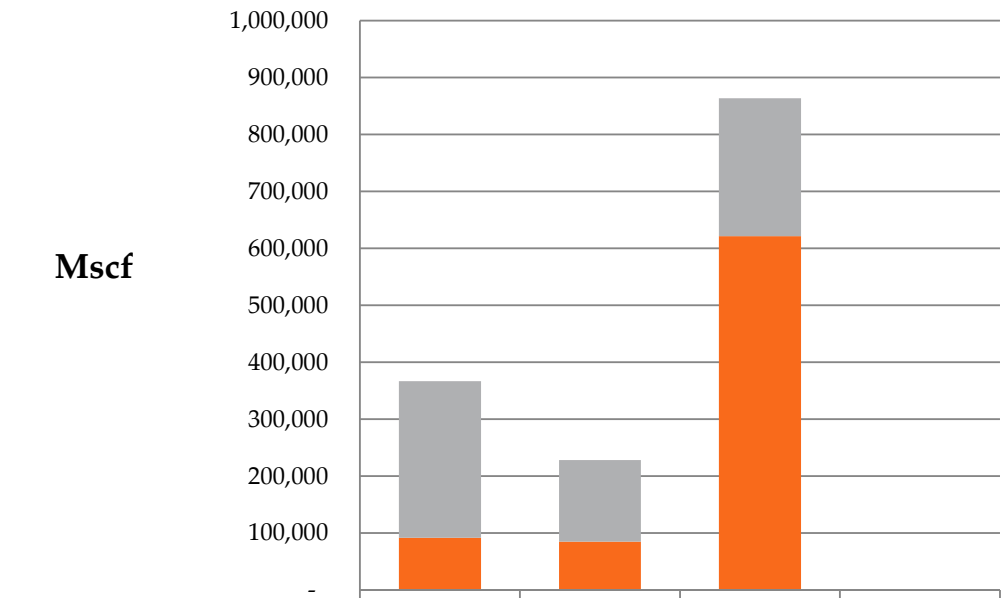
(2) New Methane Leaks in 2015 by Grade:

All utility companies listed the number of methane leaks discovered in 2015. They provided detailed information for such leaks including: the grade type, emission source, pipe size, date discovered, date repaired. The size of the leak volume was estimated using EFs provided in the data request that were primarily based on the 1996 GRI study.[42] A graph of leak volumes by grade in 2015 is shown in Figure 4 with corresponding proportions shown as percentages in Table 3. The grade 3 leaks that go unrepaired comprise the largest volume of leaks. There also could be a safety co-benefit from more frequent survey cycles by finding and fixing grade 1 leaks sooner. The leak counts by grade are found in Figure 5 with corresponding proportions shown as percentages in Table 4.

There is a significant volume of estimated leaks in the un-surveyed areas of the Distribution system that if detected sooner by employing shorter survey cycles (e.g. from a 5-year to 3-rotation) could provide an immediate one-time reduction from detecting and repairing leaks sooner. This assumes the leak rate will not change in the near future so that once the leak repairs reach a new equilibrium; leaks will occur at basically the same rate over time and get fixed within the new survey cycle timeline.

[42] http://www.cpuc.ca.gov/General.aspx?id=8829.

Figure 4: Distribution Mains and Services Graded Leaks:



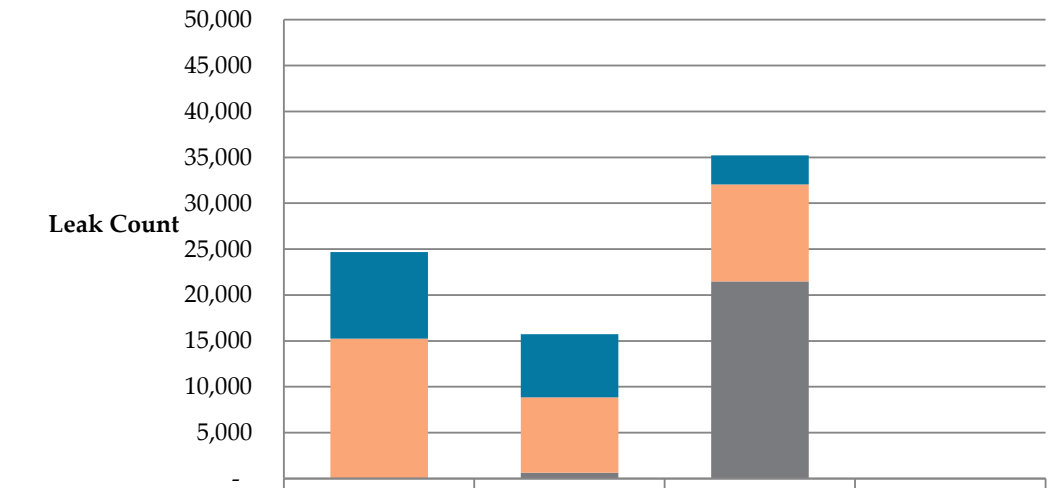
	1	2	3	Total
Estimated Emissions from Un-Surveyed Territory	274,956	143,081	242,456	660,493
Emissions from Open Leaks	91,580	84,977	621,349	797,906
Total	366,536	228,058	863,805	1,458,399

Note: The leak volume includes the estimated leaks in the un-surveyed portion of operator's service territories based on the leak occurrence rate by grade. Staff took the proportion of leaks discovered in 2015 during surveys and applied that ratio to the leaks estimated in the un-surveyed areas.

Table 3: Distribution Mains and Services Contribution to Leak Volume Percentages by Grade:

Grade	1	2	3	Total
Estimated Emissions in Un-Surveyed Territory	19%	10%	17%	45%
Emissions from Open Leaks	6%	6%	43%	55%
Total	**25%**	**16%**	**59%**	**100%**

Figure 5: Distribution Mains and Services Leak Counts by Grade:[43]



	1	2	3	Total
Leaks Repaired in 2015	9,450	6,902	3,139	19,491
Estimated Leaks in Un-Surveyed Territory	15,220	8,190	10,578	33,987
Open Leaks at 12/31/15 Carryover to 2016	25	648	21,483	22,156
Total	24,695	15,740	35,200	75,634

Table 4: Distribution Mains and Services Leak Count by Grade Percentages:

Grade	1	2	3	Total
Leaks Repaired in 2015	12%	9%	4%	26%
Estimated Leaks in Un-Surveyed Territory	20%	11%	14%	45%
Open Leaks at 12/31/15 Carryover to 2016	0%	1%	28%	29%
Total	**33%**	**21%**	**47%**	100%

[43] These counts do not include above ground leaks because the emissions are included in the customer MSA emissions mixing in the count of leaks in these charts would distort the count and emissions comparisons.

In the 2014 Joint Report, one of the notable findings was that ungraded leaks and vented emissions made up the majority of emissions, and this holds true for 2015 but to a lesser extent. However, the fact that a majority of emissions still comes from ungraded leaks and vented emissions supports the continued focus on these sources of emissions for reduction opportunities.

As mentioned earlier, a grade 1 leak represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. A grade 2 leak is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard. A grade 3 leak is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous, and usually must be rechecked periodically.[44]

(3) Open Graded Leaks Being Monitored or Scheduled for Repair:

A few utilities indicated that they have no open leaks. Those that reported open leaks classified them into graded and ungraded leaks. The graded leaks are found in pipeline delivery systems whereas the majority of ungraded leaks that would be monitored are found in station facilities or customer meter sets. In general, the utilities have a good system for identifying leaks, and tracking them until repaired. Grade 2 leaks are a concern because the time to repair some grade 2 leaks appears to take longer than required by law.[45] Because utilities used cyclical surveys, all open leaks get rechecked and evaluated to ensure their grading is consistent with the current condition of the leak. The pipeline grade 3 leaks make up a significant portion of open leaks.

Customer MSAs are largest single source of estimated emissions. However, MSA emissions are based on the population of meters times an EF. The majority of actual leaking MSAs are non-hazardous; those that are hazardous are repaired on a similar protocol as grade 1 and 2 leaks. The utilities are not required to grade MSA leaks and other types of above ground leaks. However, any they identify as hazardous must be repaired in accordance with regulations.

The data request also required the utility companies to submit a list of all open leaks from 2009 to 2014. There was also concern regarding the year the leak was

[44] https://en.wikipedia.org/wiki/Gas_leak

[45] Per PHMSA - Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered: a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type and soil conditions (such as frost cap, moisture and natural venting).

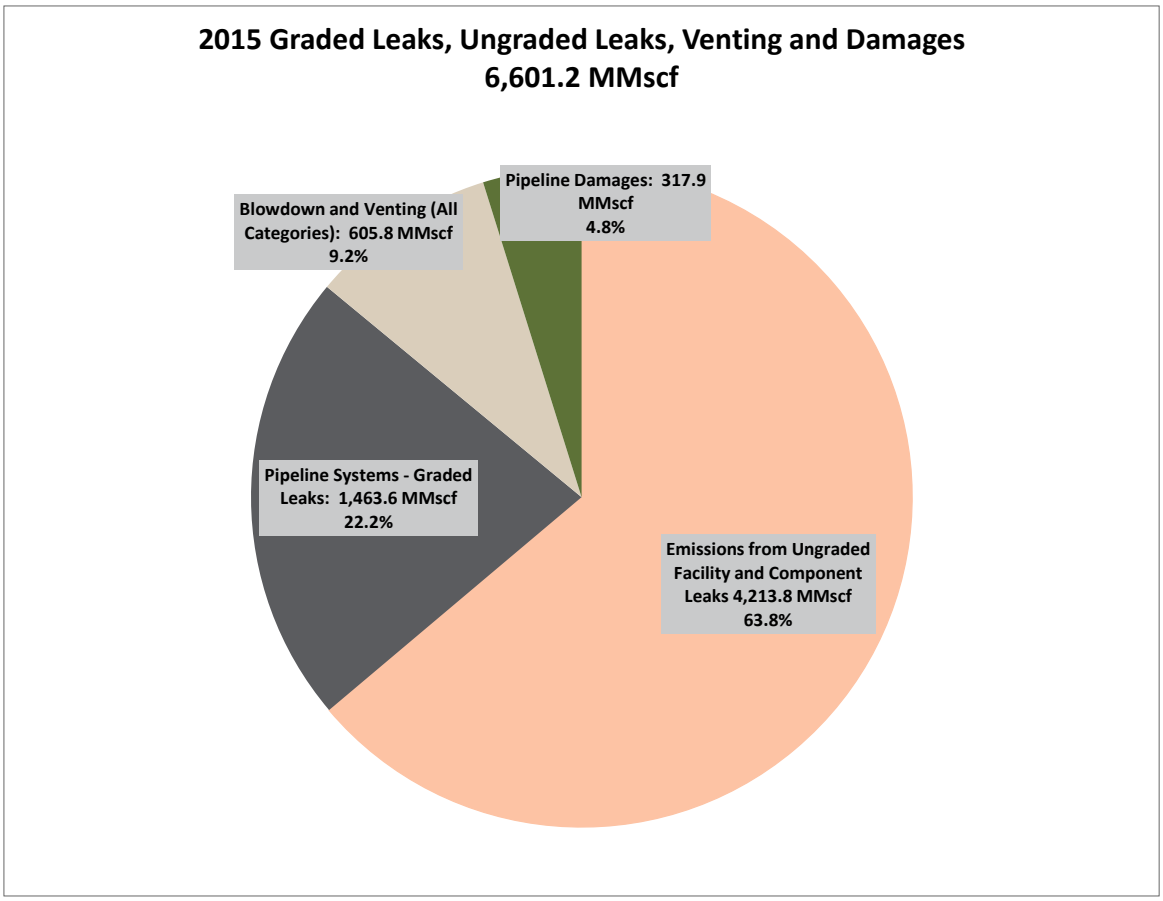
discovered and whether open leaks are rolled over into the next year and included in the emissions volume counted in each period until repaired. For example, a leak discovered in 2013 that was still leaking in 2015, and repaired in 2015, was included as an open leak during 2015 for purposes of estimating 2015 emissions. All emissions from graded leaks, no matter when detected during 2015 surveys, were calculated as if they were discovered on January 1, 2015. This was based on the concern that leaks occur prior to being detected and since we do not know when they began leaking, the utilities used January 1, 2015 to calculate 2015 emissions.

(4) Best Estimate of Gas Loss Due to Ungraded Leaks:

The natural gas lost due to fugitive leaks, other than graded leaks and not associated with venting, blowdowns or pipeline damages equates to 4,213.8 MMscf or 64% of the total reported emissions. For the purposes of this report, ungraded leaks are made up of fugitive leaks from customer meters, M&R stations, compressor stations and associated components, pipeline components and odorizers, storage facilities (compressors, components, and dehydrators) those that, based on the utilities grading system, fall outside their requirements for grading. These leaks are not the same as vented emissions (9% of total) (e.g. planned or unplanned blowdowns, releases etc.) and comprise a relatively significant volume of gas release harmful to the atmosphere.

Because of the large amount of estimated emissions that come from infrastructure in M&R stations, compressor facilities, MSAs and component equipment greater focus on leak mitigation through better designed equipment and facilities, use of better maintenance materials or practices, or improved operating practices should provide incremental emissions reductions over time, which when taken as a whole significantly reduce emissions.

Figure 6: Graded Leaks, Ungraded Leaks, Venting, and Damages:



(5) Baseline System-Wide Emissions Rate:

SB 1371 requires the establishment and annual monitoring of a system-wide leak rate for the transmission and distribution system.[46] The 2015 system wide emissions rate for SB 1371 utilities is 0.32% based on the numerator of 6,601.2 MMscf and denominator of about 2,056,950 MMscf throughput.

In this report, utilities provided their throughput figures used to calculate the emissions rate. Staff determined the System-wide Leak Rate using the total emissions from all source categories divided by the Total Annual Volume of Gas Transported.

Staff defined the Total Volume of Gas Transported as the combination of the following five sources:

1. Total Storage Annual Volume of Injections into Storage

[46] PUC Code Section 975(e)(6), Article 3 added by Stats. 2014, Ch. 525, Sec. 2. Effective January 1, 2015.

2. Total Transmission Annual Volume of Gas Used by the Gas Department
3. Total Transmission Annual Volume of Gas Transported to or for Customers in State
4. Total Transmission Annual Volume of Gas Transported to or for Customers out of State
5. Total Distribution Annual Volume of Gas Used by the Gas Department.

Every effort was made to prevent duplication of quantities that flow through the storage, transmission and distribution systems such that that volume was intended to be counted only once in the denominator.

The "Leak Rate Data" (tab two the Appendix 8 – Summary Workbook) shows the type and format of the information requested. [47]

Staff noted in the 2014 annual report, that "(t)he main reason given for error in calculating the system-wide leak rate was that LAUF volume is many times larger than gas lost due to known leaks and emissions. This could be due to atmospheric pressure and temperature during the metering process as well as metering accuracy. Overall, the utility data submitted to date indicate that leaks are far less than 1% of total gas moving through California's gas system making it difficult to quantify the volume on a system basis using meter readings."[48]

The stated concern was that the leak rate calculation led to double counting, or to negative quantities, or that throughput of the gas was incorrectly attributed to a different utility. In addition, some questioned whether there should be a separate storage, transmission and distribution emission rate. Due to the issues found with determining a California emissions rate in 2014, the 2015 data reporting templates were changed to better define throughput and estimate the emissions rate for this report.

This report does not separate the reporting of a storage, transmission and distribution leak rates, because of the difficulty in allocating the throughput to each sector. Further defining how to allocate the throughput data may help determine the leak rates for storage, transmission and distribution in the future.

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[47] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9259

[48] Joint Air Resources Board/California Public Utilities Commission Staff report, Pgs. 12-13: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10263

Lessons Learned

Further Work:

After the 2014 gas emissions report was issued significant effort went into revising the templates and data requested for the 2015 annual gas emissions report. The 2014 information received from stakeholder filings revealed that the information request needed incremental improvement, particularly more work needed to be done in quantification of leak volume, validating and updating EFs to better approximate category population emissions, and increasing the confidence in the methods that would ensure consistent and comprehensive reporting across utilities.

As such, based on formal comments by parties, Staff released a new data request spreadsheet.[49] The data request included a request for more detailed component emissions data, and asked for more event or equipment specific data. Staff also recognized the need to design a simple and reliable definition for quantifying system wide leak/emission rate and formalized a template for respondents to use to ensure consistency in the information. The Staff proposed a system wide leak/emissions definition that focuses on the total volume of emissions (estimated and actual for the period) divided by throughput (purchased, transported, and produced gas) for the transmission and distribution side with a corresponding rate for storage accounting for the amount stored.

The data templates improved the report submissions, but there were small gaps that required Staff to contact respondents for clarification and to work through missing or incomplete data.

2015 Issues and Opportunities:

1. The revised and improved templates helped develop a more consistent record of emission estimates for 2015. All the reporting entities did a very good job responding to the format of the data templates and addressing subsequent follow up questions from Staff. It was clear that the improvements made after the last annual report made a significant difference.

2. During the process of reviewing the data submissions, Staff found that the templates developed for reporting data did not contemplate counting emissions from leaks that occur in the utility's un-surveyed service territory.

[49] April 11, 2016: Administrative Law Judge's Ruling Issuing Staff Data Request Regarding 2016 Annual Reporting Requirements and Directing Responses by June 17, 2016, R.15-01-008. The appendices, referred to in the April 11, 2016 ruling, are posted at: http://www.cpuc.ca.gov/General.aspx?id=8829

One utility proactively calculated the emissions within its un-surveyed service territory and brought this to the attention of Staff. Staff determined that all utilities should estimate emissions from the portions of un-surveyed areas for this report. The utilities worked with Staff during the summer to develop a consistent emissions estimation method. The method was employed to estimate emissions occurring in the un-surveyed portions of their service territory. During 2017, Staff plans to conduct a working group meeting to share the methodology and algorithms used to estimate the total leaks in the utilities territory and refine it where possible. The templates will be updated with the changes noted during these meetings for use in the next reporting cycle (See Appendix E for a table of proposed template changes). Understanding the amount of leaks occurring in the entire service territory facilitates better estimates of pipeline emissions.

3. The 2014 and 2015 annual emissions reports used a mixture of emission estimation methods, such as population counts times EFs, leak detection, direct measurement and engineering estimates. The various methods used to estimate emissions may be sufficient for establishing a baseline from which to start measuring reductions, but going forward the emissions estimation methods should be reviewed periodically to continually improve the emission estimates going forward. More emphasis needs to be placed on finding ways to quantify emissions from infrastructure components and equipment.

4. Currently the use of EFs to estimate emissions from population (e.g. of pipeline miles, or meter sets) based estimates means that the only way to improve the emissions from these sectors would be to change the EF or the population. Greater reliance on scientifically based measurements and readings of actual leaks needs to be established to determine whether emissions reductions actually occur. The lack of effective and efficient volumetric measurement tools creates challenges implementing direct measurement of emissions. Additionally, there are challenges to cost effectively measure and repair minor underground leaks. While emission estimates based on EFs may be expedient and low cost, it appears advances in emissions reductions will be increasingly difficult to achieve unless fact based quantification methods become common practice. Fact based quantification methods become increasingly important for prioritizing mitigation actions and avoiding costly minor reductions.

5. Related to the concern about relying on EFs to estimate emissions, using outdated or obsolete EFs is an additional concern. The 1996 GRI EFs used for the 2015 Joint Report need to be reviewed because going forward they may not be appropriate due to their age and their applicability to California infrastructure. However, these were determined to be the most reliable EFs to consistently estimate emissions for 2015 annual report. Given that there are significant differences in topography and geography within a utility territory let alone the differences between the north and south parts of the state. Staff plans to review the EFs to identify issues with emission estimates, whether better EFs exist and, which EFs should be used going forward. Staff will have a workshop or webinar to vet these potential improvements.

6. Staff reviewed and analyzed the Data Reports and determined that some information in the Data Reports needed revision or augmentation that required follow up with the utilities. As a result, utilities resubmitted some of their data and responded to Staff questions. The additional time to vet the data submission was worthwhile in that it provided greater confidence in the consistency and integrity of the categorization of data. This exercise provided insight into what areas of the Data Templates may need to be updated or revised for clarity and consistency. For example, the data reporting templates though much improved over 2014 versions still did not clearly identify some information that should be reported and this caused confusion and inconsistent reporting. The inclusion of a sheet that calculates estimated leaks from un-surveyed areas should be added to the Appendix 4 workbook for Distribution Mains and Services. Breaking down the summary totals and counts by leak grade as well as by year detected would facilitate grouping and analyzing the data. In addition, the lack of column totals made following the data from supporting sheets to the summary sheet more difficult; therefore, column totals should be added to all worksheets and a summary sheet that ties back to each total within the workbook sheets provided as well. Staff also found that the templates data cells were not always clear and the intent not well defined. Therefore, the templates still need more clarification and better definitions of intent to help respondents provide the desired data. (See Appendix E for a table of proposed template changes.)

7. The process for updating reporting templates should be completed by March 31 of each year to facilitate capturing the data (See Appendix E for a table of proposed template changes). Then the report could be submitted by June 15 of each calendar year. This should be proposed in the First Phase Decision.

Going forward, familiarity with the data templates will increase with greater understanding both for respondents and Staff.

8. In the templates contained in Appendices 1, 4, and 6 for Transmission Pipeline, Distribution System Pipelines and Customer Meter Leaks respectively, respondents provided lists of their leaks. The transmission system template asked for graded and ungraded leaks, the Distribution System template asked for graded leaks and the Customer Meter Sets templates asked for ungraded leaks. During the consolidation of data, Staff used the number of miles of transmission pipeline times an EF to estimate pipeline emissions because there was concern that basing the emission estimate on existing leaks would not provide a reasonable estimate of emission from pipelines given the EF recommended was based on miles of pipe. There was no way to use a spot leak times an Emissions/mile EF that would provide a reasonable estimate of the Transmission pipeline leak volume. Staff learned that a method of quantifying the leak volume is a requirement before using a discrete leak count to estimate emissions volumes.

9. The second tab of the Appendix 8 Summary, labelled "leak rate data" requested that emissions be separated into graded, non-grade, and (vented) emissions where possible. After consolidating the leak rate data, Staff observed that the templates did not clearly state what should be put into each of the categories, and it appeared that respondents were confused as to what information was to be reported into each column. Staff recommends that a future workshop be held to work with respondents to define what information belongs in each of the types of emissions for the three segments being evaluated (Storage, Distribution and Transmission systems).

Conclusion

The report describes a framework for understanding the data submitted in the June 17, 2016, reports and subsequent submittals. Some of the major findings are:

- The baseline emissions estimate for 2015 from SB 1371 sector utilities totals 6,601.2 MMscf, equal to 2.96 MMTCO2e using the AR4 100-year methane GWP or8.51 MMTCO2e using AR4 20-year methane GWP, which provides a starting point to measure future natural gas emission reductions.
- Significant changes to emission factors (EFs) could occur based on improved information. Staff would need to consider the implications of the change and potential need to adjust the baseline to avoid incorrect accounting.

Nevertheless, the categories with the highest emission levels should be the starting point for establishing best practices to achieve the greatest amount of reductions for resources expended.

- The vast majority of ungraded emissions (64%, Figure 6) come from the components and equipment found throughout the delivery system. By parsing the emissions and identifying the volume of emissions and their sources, utilities can focus on the most cost-effective means to reduce emissions. By using actual emissions data, utilities should be able to address operating and maintenance practices, and component designs and materials to facilitate emission reductions.
- Among leaks that have been categorized as potential hazards, the grade 3 leaks make up a significant amount of leaks that are carried over year after year, making up 59% of the volume of all graded leaks. Even though grade 3 leaks are not considered a safety threat, cost-effective ways should be found to fix them sooner to reduce this persistent source of emissions.
- About 10% of the total emissions were from graded leaks in un-surveyed areas, estimated to occur between leak survey cycles. By reducing leak survey cycle times, the leaks occurring between cycles will emit for shorter lengths of time until they are detected and repaired. This effort should reduce emissions from graded leaks.
- Use of EFs may be acceptable in the short term for establishing the baseline emission levels. However, in order to better quantify emission reductions over time utilities must devise better ways to measure actual leak volumes. Relying on EFs may not fully account for emissions and reductions over time (e.g. every leak fixed is assumed to be emitting the same amount). Because it is difficult to quantify the actual volume of leaks and emissions, more work is needed to develop and improve California specific EFs until actual emissions measurements are available for the sources where it is feasible to directly measure emissions.
- Continuing refinement and improvement of the data reporting templates should increase transparency, and provide formats that consistently capture reliable leak and emission data for measuring changes in natural gas emissions.

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Appendix A: Methods Used for Reporting and Estimating Leaks and Emissions

Rulemaking (R.) 15-01-008 to Adopt Rules and Procedures Governing Commission Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leaks Consistent with Senate Bill 1371, Leno.

Explanation of Methods Used for Reporting and Estimating Leaks and Emissions (Based on Appendix 9 of Data Request).

System Categories	Emission Source Categories	Emission Factor (EF) Source or Method	Description
Transmission Pipeline	Pipeline Leaks	INGAA	Due to lack of details about each leak (e.g. size of orifice, duration of leak, and volume) pipeline operators were instructed to provide emissions using the approved EF by number of miles of pipeline. It was determined that use of the emission factor from INGAA Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage - Volume 1 GHG Emission Estimation Methodologies and Procedures (September 28, 2005 - Revision 2) - Table 4-4 study would be the best available for Transmission Pipeline emissions at this time.
	All damages (as defined by PHMSA)	Engineering Estimate	Event specific emissions data reported where emissions were estimated either from modelling or size of breach using pressure and duration to calculate the emissions.
	Pipeline Blowdowns	Engineering Estimate	The emissions calculated based on unique equipment attributes using the recommended EF most closely associated with that component to estimate emissions volume (corrected for pressure and temperature). These emissions were assumed to emit for the entire year. Actual measurements of emissions are difficult to calculate due to variations in operations and impact of new equipment versus old and the efficacy of maintenance practices.

	Component Emissions: Pneumatic Devices Pressure Relief Valves	GRI (1996)/ MRR	The emissions from components associated with transmission pipeline operations are based on the recommended EF's outlined in Appendix 9 of the Data Request. In some cases, the components did not meet the definition for the EFs and discrete approximations based on manufacturer provided leak rates, direct measurement of the different operating states as well as the for specific values recommended for use in calculating component specific leaks times number of units of equipment.
	Odorizer (Odorizer and Gas Sampling Vents)	TCR	The EF's recommended in Appendix 9 were used where directly applicable, however where transmission pipeline dehydrator equipment did not match the pipeline operators used the discrete equipment attributes and operations profile to estimate emissions. The methods used appeared to provide the best estimate of emissions given the variety and operating context of these facilities.
Transmission M&R	M&R Stations: - Farm Taps & Direct Industrial Sales - Transmission-to-Transmission Company Interconnect	MRR / GRI (1996)	The emission estimate for M&R stations are based on the EF's recommended in Appendix 9 multiplied by the population of each type of M&R station.
	M&R Leaks	MRR	The discrete leaks for M&R stations would be captured in the recommended EF's used to estimate the M&R station emissions and only where it could be determined that inclusion of discrete M&R leaks were not duplicated were they included in the count of emissions for this category.
	M&R blowdown	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume being vented corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
Transmission Compressor Stations	Compressor Equipment - Centrifugal and Reciprocating.	MRR	The emissions calculated based on the direct measurement of each compressor unit given its operating state and pressure, and then the emissions are based on number of operating hours in each operating state.

	Equipment and pipeline blowdowns	MRR	Blowdown emissions were estimated based on the calculation of the unique equipment volume being vented corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components.	MRR	The equipment and component emissions are based on the leaks detected at the compressor stations times the recommended EF for that type of equipment per Appendix 9.
	Compressor Station Storage Tanks	MRR	These emissions are based on discrete tank pressure fluctuations due to exterior temperature fluctuations. The initial volume of gas release calculation is based on the starting and ending pressures assuming a constant temperature.
Distribution Mains and Services Pipelines	Pipeline Leaks - Below Ground	GRI (1996)	The emissions from leaks detected in 2015 in Distribution Mains and Service pipelines are calculated assuming that the leak was emitting from the first day of the calendar year through date of repair, or the entire year if not repaired in 2015, times the recommended EF. For identified leaks carried over from prior years the emissions are calculated from the beginning of the year through repair date (if repaired in 2015) or end of year times the recommended EF. In addition, leaks occurring in un-surveyed parts of operator's service territory were estimated based on the leak occurrence rate in the surveyed portion of the territory extrapolated based on number of years in the survey cycle to come up with the number of expected leaks in the un-surveyed territory times the recommended EF. This method of estimating the emissions from leaks occurring in un-surveyed portions of the service territory is considered a reasonable way of approximating the emissions and takes into account the frequency of leak detection surveys.
	Pipeline Leaks - Above Ground	GRI (1996)	See above for below ground leaks. Above ground leaks associated with MSAs are not counted in the volume or the numbers of leaks in order to prevent misleading representation of emissions as well as potential for duplication of emissions volumes.
	Blowdowns and Venting	MRR	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.

	All damages (as defined by PHMSA)	MRR	Emissions from damages for AG Non-hazardous and MSA damages are calculated based on company emission factor for above ground facilities times the number of days leaking. For AG Hazardous and Below Ground Code 1 damages, emission was estimated based on based on engineering calculation using pipe size, damage opening size, and duration. For Code 2 and Code 3 damages, the emission factor for Distribution pipeline leaks was used. Where an estimate was not made at the time of the event, the emission was estimated from population of similar events with respective pipe material and pipe size.
	Components - Pneumatic Devices	Engineering Estimate	Emissions from components such as pneumatic devices are based on manufacturer specifications for bleed rate given the pressure.
	Odorizer (Odorizer and Gas Sampling Vents)	TCR	Not applicable for this category.
Distribution M&R Stations	M&R Stations: - Farm Taps & Direct Industrial Sales - Transmission-to-Transmission Company Interconnect	MRR / GRI (1996)	The emission estimate for M&R stations are based on the EF's recommended in Appendix 9 multiplied by the population of each type of M&R station.
	Blowdowns	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components	Engineering Estimate	The emissions from components are captured in the EF used on a station by station basis and the discrete information on a subset of components in the facility would duplicate emissions and present misleading count information. Until further work can be done with more comprehensive survey techniques relying on the recommended EF's on a station by station basis is considered the best estimate of emissions at this time.

Commercial, Industrial and Residential Meters	Residential and Commercial Meters	GRI (1996)	The emissions for this category is based on the MSA population count times the recommended EF per Appendix 9. There is substantial work currently being done to update EF's for MSAs and in future any updated EF's could be backward applied to 2015.
	Vented Emission from MSA	Engineering Estimate	Emissions from venting MSAs are based on the number of events times the estimated volume release by MSA and/or the type of activity.
Underground Storage	Facility Leaks	GRI (1996) / Engineering Estimates	Emissions in this category are based on EPA GHG Subpart W data EF's multiplied by the number of units of each equipment type.
	Compressor	Engineering Estimate	Emissions from storage facility compressors are calculated in the same manner as for compressors in other categories. See the description in the Compressor Station category.
	Blowdown and Venting	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components	MRR	Component emissions are based on the leaks detected during GHG leak survey pursuant to the GHG Mandatory Reporting Regulation and each component's EF times the population count. All leak and component emission estimates are based on the assumption that the leak is leaking the entire year.
	Dehydrator Emissions - Venting	MRR	The dehydrator emission estimate is based on the TCR Protocol for dehydrators.

January, 2017

Appendix B: Definitions

For the purposes of SB 1371, the definitions of "leak" and "gas -loss" and the formula for calculating a "system-wide gas leak rate" were defined in a different manner than elsewhere. A "leak" was defined as any breach, whether intentional or unintentional, whether hazardous or non-hazardous, of the pressure boundary of the gas system that allows natural gas to leak into the atmosphere. In essence, any vented or fugitive emission to the atmosphere is considered a "leak". Examples of leaking components include defective gaskets, seals, valve packing, relief valves, pumps, compressors, etc. Gas blowdowns during the course of operations, maintenance and testing (including hydro-testing) were also included as leaks. Consequently, this leak definition is broader than the Pipeline Hazardous Material and Safety Administration's (PHMSA) definition.

The gas utilities are required by Federal Law, 49 CFR 192, to survey their systems for leaks, which could be hazardous to public safety or property. To accomplish this, the gas utility companies developed graded leak programs to detect, prioritize and repair the safety related types of leaks. The same definitions are used within this report and are as follows:

- Graded Leaks –hazardous leaks or, which could potentially become hazardous as described below:
    - A "grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.[50]
    - A "grade 2 leak" is recognized as being non-hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.51
    - A "grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.[52]

- Vented Emissions are releases of gas to the atmosphere, which occur during the course of operations or maintenance, for a safety reason. Some examples are:
    - Purging (a.k.a. "blowdown") gas prior to hydro-testing a line.

50 Refer to G.O. 112F for more information.
51 Ibid.
52 Ibid.

- Gas releases designed into the equipment function, such as gas emitting from relief valve vents or pneumatic equipment.
- Gas releases caused by operations, maintenance, testing, training, etc.
- Ungraded Leaks are the remaining leaks, which are not hazardous to persons and/or property.

For further information please see CPUC General Order (G.O.) 112, Revision F.

Lastly, in 2014 the system-wide gas leak rate was calculated as a percent of total input for the 12 months ending June 30 of the reporting year. However, Staff determined that there were problems with this calculation and opted not to report a leak rate using this formula. The formula for calculating a system-wide gas leak was written as follows:

Pipeline Hazardous Material and Safety Administration (PHMSA) Modified Equation for Lost and Unaccounted for (LAUF) Gas:

[(Purchased gas + produced gas + transported gas entering the gas system) minus (customer use +company use + appropriate adjustments + gas injected into storage + transported gas leaving the gas system)] divided by (Purchased gas + produced gas + transported gas entering the gas system) = System Wide Gas Leak Rate.

Note: transported gas includes gas purchased by customers and transported in common carrier pipelines.

In section 5, "Baseline System-Wide Emissions Rate," Staff determined the value for 2015 to be 0.32% by using the total natural gas emissions from all source categories (6,601.2 MMscf) divided by the Total Annual Volume of Gas Transported (2,056,950 MMscf). The five sources for Total Annual Volume of Gas Transported are listed on pages 29 and 30 of this report.

January, 2017

Appendix C: Article 3, Section 975 (c) and (e)(6)

Article 3. Section 975

(c) As soon as practicable, the commission shall require gas corporations to file a report that includes, but is not limited to, all of the following:

(1) A summary of utility leak management practices.

(2) A list of new methane leaks in 2013 by grade.

(3) A list of open leaks that are being monitored or are scheduled to be repaired.

(4) A best estimate of gas loss due to leaks.

(e) The rules and procedures adopted pursuant to subdivision (d) shall accomplish all of the following:

(6) to the extent feasible, require the owner of each commission-regulated gas pipeline facility that is an intrastate transmission or distribution line to calculate and report to the commission and the State Air Resources Board a baseline system-wide leak rate, to periodically update that system-wide leak rate calculation, and to annually report measures that will be taken in the following year to reduce the system-wide leak rate to achieve the goals of the bill.

Appendix D: Conversion of Natural Gas to Carbon Dioxide Equivalents

The conversion of natural gas volume to carbon dioxide equivalent mass requires the use of GWP. ARB used GWP25 (100-year value) from the IPCC, AR4, for the 2014 GHG emissions inventory. The following calculations show the conversion of the total natural gas emissions from this report. The conversion was done in two steps. In the first step, the calculation shows the volumetric natural gas that contains exactly one metric ton of methane.

$$1\ MT\ CH4 * \frac{2{,}204.62\ lbs\ CH4}{1\ MT\ CH4} * \frac{1\ lb\ mole}{16.04246\ lb\ CH4} * \frac{379.48\ scf\ of\ CH4\ gas}{1\ lb\ mole}$$

$$* \frac{1.0\ scf\ of\ natural\ gas}{0.934\ scf\ of\ CH4\ gas} * \frac{1\ Mscf}{1{,}000\ scf} = 55.835\ Mscf\ of\ natural\ gas$$

Using this volumetric unit, the 2015 total natural gas emissions, 6,601 MMscf, is equivalent to about 3.0 MMTCO2e, as shown below:

$$6{,}601{,}169\ Mscf\ natural\ gas * \frac{1\ MT\ CH4}{55.835\ Mscf\ of\ natural\ gas} * \frac{25\ CO2e}{1\ CH4} *= 2{,}955{,}671\ MT\ CO2e$$

ARB has also used GWP 72 (AR4, 20-year) in the Short Lived Climate Pollutant Plan and Oil and Gas Regulation. Based on the higher GWP, the 2015 total natural gas emissions, 6,601 MMscf, is about 8.5 MMTCO2e, as follows:

$$6{,}601{,}169\ Mscf\ natural\ gas * \frac{1\ MT\ CH4}{55.835\ Mscf\ of\ natural\ gas} * \frac{72\ CO2e}{1\ CH4} *= 8{,}512{,}332\ MT\ CO2e$$

The use of 1.0 scf of natural gas per 0.934 scf of CH4 gas accounts for composition of natural gas being not 100% methane. The American Gas Association published a value of 93.4% to be used as a default methane concentration that is comparable to what utilities reported.[1]

The standard cubic foot "scf" for measuring gas is based on 60 degrees Fahrenheit at atmosphere pressure.

In addition, utilities reported trace amounts of concentration for ethane, inert gases, and other elements and compounds. There was not an entry for carbon dioxide

explicitly, and so it cannot be assumed that all of the inert gas was carbon dioxide. A calculation was performed that showed CO2 emissions from the inert gases would be less than 0.1% of the total, and is excluded in this report.

Footnote:

1. AGA, GHG Guidelines, page 39, April 18, 2008, http://s3.amazonaws.com/zanran_storage/www.aga.org/ContentPages/18068841.pdf

January, 2017

Appendix E: Table of Proposed Changes to Data Request Templates

Application	Proposed Template Modification	Explanation
Appendices 1 through 7; All Template sheets.	Include a note to each tab for the utilities' formula used to calculate the Annual Emissions, rather than copy and paste-as-value. Please do not include VLOOKUP unnecessarily in the data sheets.	By showing the formula, the review process is expedited. It will also be apparent if EFs or Engineering calculations are used. Staff is interested in seeing calculation assumptions used in estimating emissions of blowdowns. In cases where the formula cannot be shown since it is more complicated than the multiplication of terms on the row, please note in the explanations column.
Appendices 1 through 7; All Template sheets.	A note has been added to each tab for utilities to include the AutoSum function at the end of the Annual Emissions column. Then highlight the total cell orange.	There have been instances of an error made in transferring the total from individual appendices with the Summary 8 appendix.
Appendices 1 through 7; All Template sheets.	A note has been added to each tab to include the total leak, event and population counts.	This will expedite the review process.
Appendix 4: Distribution Mains and Services	Include a new tab for Estimated Un-surveyed Leaks for estimating the number of leaks, and their associated emissions, from un-surveyed mains and services. A standardized calculation methodology is also proposed.	In the review of 2015 Data, it became apparent that this significant emission source was not accounted for. Staff worked with utilities that do not survey all of their mains and services annually to account for leaks and estimate emissions that occur in the un-surveyed areas.
Appendix 4: Distribution Mains and Services	Include a new tab summarizing all of the pipeline leak data (e.g. un-surveyed and surveyed) for emissions, grade, and counts.	This will expedite the review and analysis process.
Appendix 4: Distribution Mains and Services	Include a new tab for capturing leaks detected from meter set assemblies during the distribution mains and services leak detection surveys. Add a note to the pipeline leaks tab to exclude any meter set assembly leaks formerly listed therein, and list them in the new tab set up to capture the MSA data.	Emissions from meter set assembly leaks are already accounted for in Appendix 7, Customer Meters. In the review of 2015 Data, the inclusion of MSA leaks on this tab required further consultation with utilities to accurately count the number of mains and services leaks and prevent double counting. Therefore, an extra tab will be added to allow utilities to capture above ground meter set assembly leak data. The estimated emissions in this new tab would not be included in the annual emissions total.

January, 2017

Appendix 4: Distribution Mains and Services	Delete the tab for Odorizers.	Odorizer facilities are not part of the Distribution Mains and Services system, therefore, there were no emissions from this category in 2015. Including a tab for this category is unnecessary.
Appendix 8: Summary Table	Two of the Emission Types listed "Graded/Non-graded Leaks" and "Non-graded Leaks/Emissions". The Emissions Types will be changed so that only one type per category is allowed. Where additional emission types exist within a category then an additional line needs to be added for the second (or third) Emission type. For example, the type "Graded/Non-Graded Leaks" would either be shown as "Graded Leaks," "Non-Graded Leaks"; or for "Non-graded Leaks/Emissions" either "Non-Graded Leaks" or "Emissions" would be used.	Staff determined that only one emissions type should be listed per category line item. For example, either the leak type should be "Graded" or "Non-Graded" but the category line item emissions data should not contain both types of emissions. This should facilitate analysis and making charts for the Joint Report.
Appendix 8: Summary Table	Include the AutoSum function at the end of the Annual Emissions column. Then highlight the total cell orange.	Staff determined that the total emissions per utility should be displayed so that it can be used as a reference when consolidating the data.
Appendix 8: Summary Table	On the tab for NG specification, Carbon Dioxide has been added.	Staff determined that carbon dioxide was necessary to be added to the list of NG specifications.

Environmental Impact Report Public Scoping Meeting for Grayson Repowering Project

Griffith Manor Park
Glendale, California
January 12, 2017
Presented by: Michael Weber

Check in at table to provide verbal comment during meeting. Each speaker is limited to 3 minutes. Visit table for additional opportunities for comment.

Stantec

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Meeting facility and safety

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Agenda

1 Meeting purpose

2 Project description

3 Initial study

4 Public comment

5 Closing remarks

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1 Meeting purpose

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California Environmental Quality Act

- Requires state and local agencies to identify environmental impacts of their actions and to avoid or mitigate significant impacts, if feasible
- Opportunity for the public to review and provide input in the process
- City of Glendale will prepare an Environmental Impact Report (EIR)

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Early Stage of EIR Public Participation

- Prepared and issued an Initial Study and Notice of Preparation of an EIR
- Public scoping meeting - seek input from the public/stakeholders regarding the SCOPE and CONTENT of the EIR

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2 Project Description

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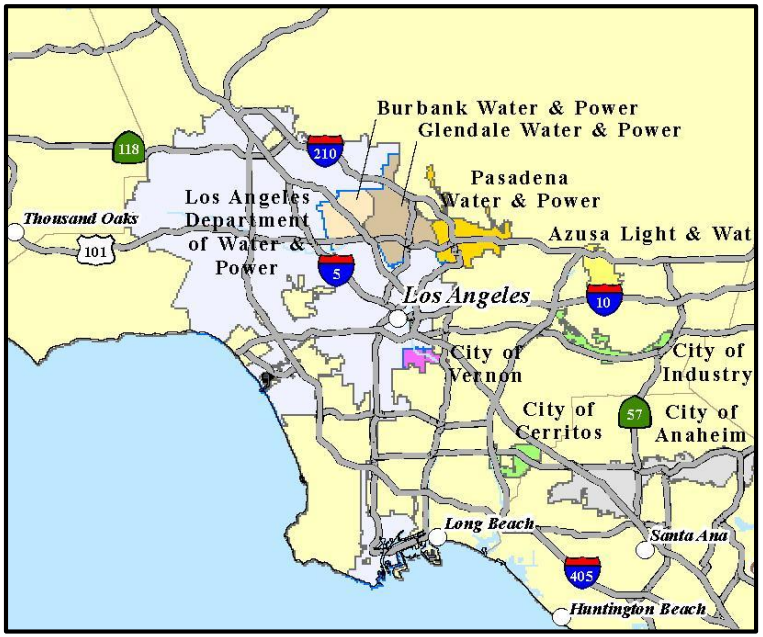
Glendale Water & Power

- Municipal utility responsible for serving the citizens and community of Glendale
- Over 33,744 water and 85,358 electric customers



Source: California Energy Commission

City of Glendale Water & Power
Your Trusted Community Utility

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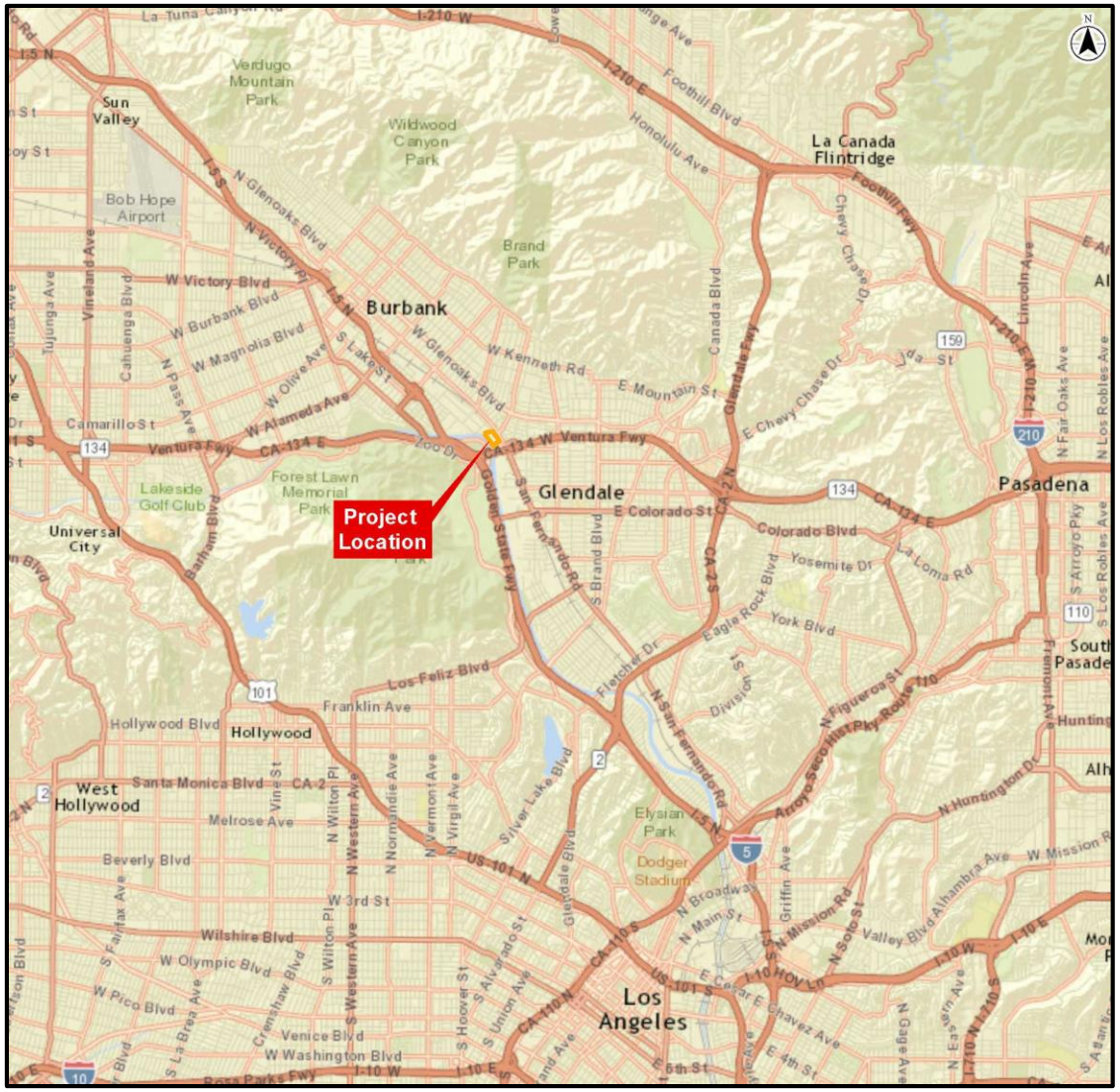
Project Location



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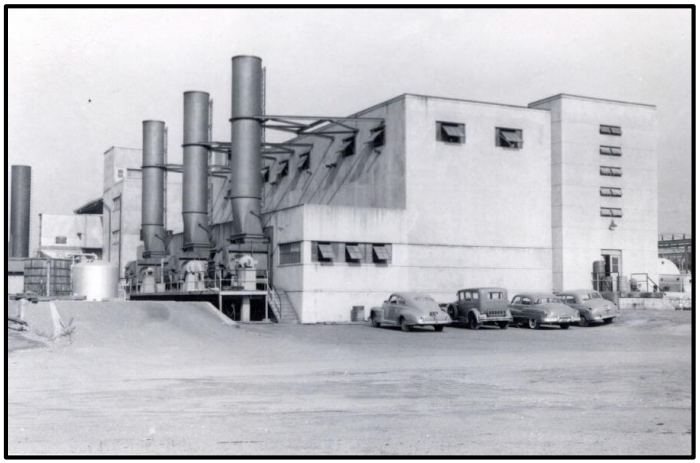
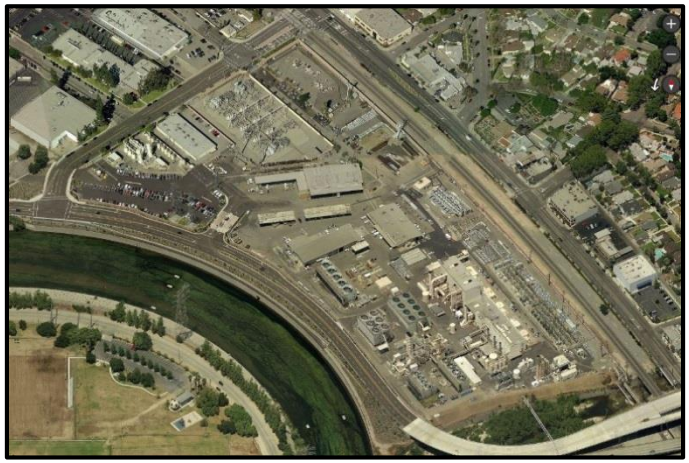
Grayson Power Plant History

- Faithfully serving the electrical power needs of the City of Glendale since 1941
- Reliability, efficiency and cost effectiveness of the existing facility has steadily declined due to age and normal degradation of the equipment





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Proposed Project

- The City of Glendale proposes to repower Grayson Power Plant at its existing location
  - Taking an old generating unit out of commission, dismantling it, and building a new, modern one at the same site
- The repowered units are more energy efficient, create less emissions, and increase reliability of the power grid
- Meet City needs per Integrated Resource Plan

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Proposed Project

- Replace 238 MW of the existing capacity with 262 MW of more efficient generation
  - Two Siemens 71 MW combined cycle units
  - Two Siemens Industrial Trent 60 MW simple cycle units
- Ancillary facilities such as cooling towers, gas compressors, new switchyard, and plant operations building
- Unit 9, a 50 MW simple cycle unit commissioned in 2003, would remain in service

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Proposed Project

Generation Units Proposed for Decommissioning	MW
Unit 1 – steam turbine-generator, built in 1941	20
Unit 2 – steam turbine-generator, built in 1947	20
Unit 3 – steam boiler turbine-generator, built in 1953	20
Unit 4 – steam boiler turbine-generator, built in 1959	44
Unit 5 – steam boiler turbine-generator built in 1964	44
Unit 8A– gas turbine-generator combined cycle plant built in 1977	30
Unit 8B/C – gas turbine-generator combined cycle plant built in 1977	60
Generation Capacity Removed	**238**

Repowering Replacement Generation Units Proposed	MW
Unit 10 - one-on-one combined cycle unit	71
Unit 11 - one-on-one combined cycle unit	71
Unit 12 - simple cycle unit	60
Unit 13 - simple cycle unit	60
Generation Capacity Added	**262**

Additional Capacity < 50 MW

MW = megawatt

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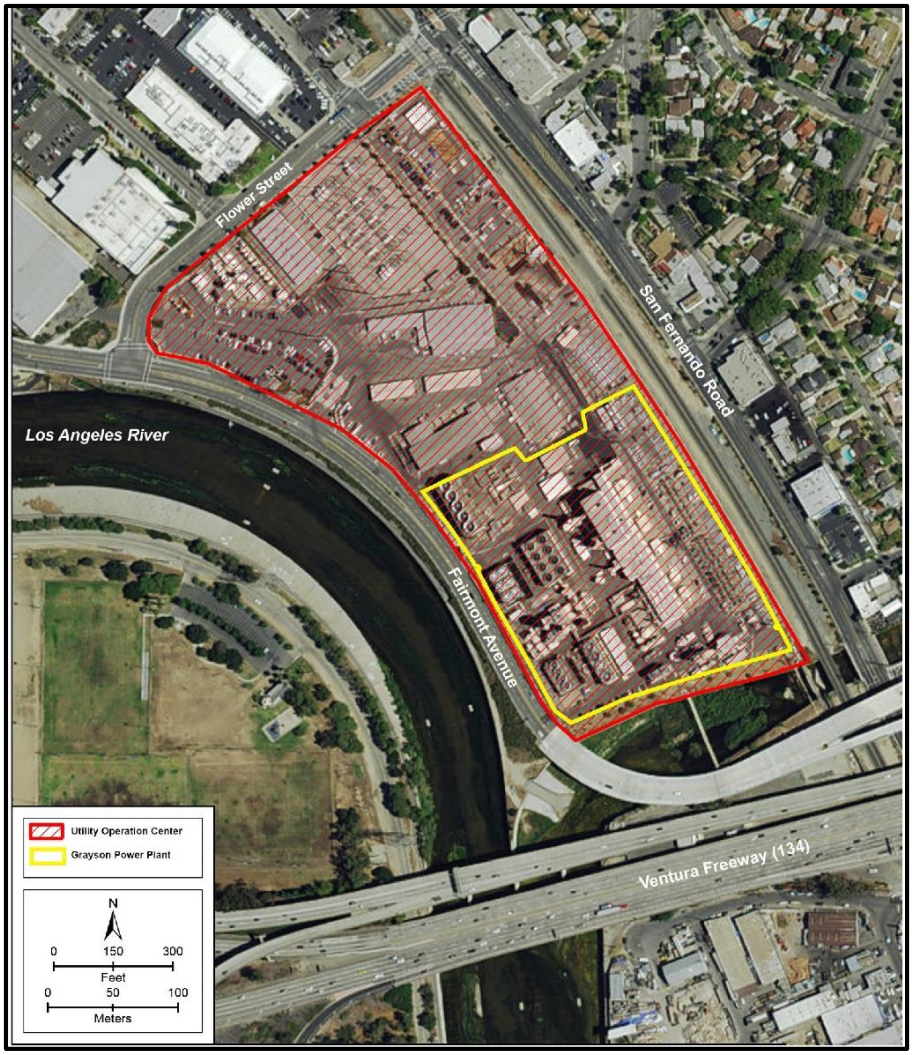
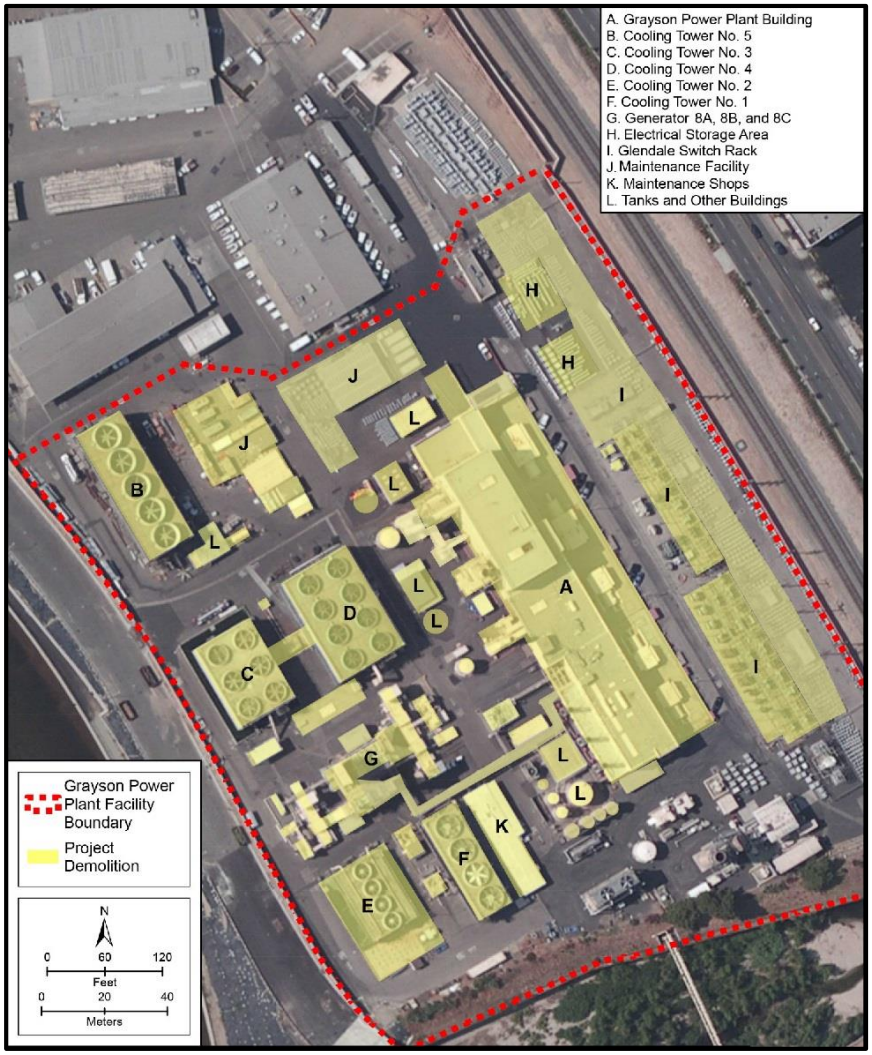
Proposed Project Demolition





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Proposed Project

① Unit 10 Combined Cycle Plant
② Unit 11 Combined Cycle Plant
③ Unit 12 Simple Cycle Plant
④ Unit 13 Simple Cycle Plant
⑤ Fairmont Switchyard
⑥ Operations & Maintenance Building
⑦ Water Treatment Area
⑧ Existing Unit 9
⑨ Future BESS

GRAYSON REPOWERING PROJECT

City of Glendale Water & Power
Your Trusted Community Utility

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Project Objectives & Benefits

- Allows increased integration of renewable energy supplies to meet regulations
  - Quick startup, ramp up and down to take advantage of renewables when available and meet demand when not
- Provide a locally controlled source of generation to minimize the City's reliance on importing power from remote coal-fired generation locations and limited transmission capacity
- Support water conservation efforts by eliminating the use of potable water for generation and using recycled water instead
- Provide reliable service and affordable rates to Glendale ratepayers

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3 Initial Study

Initial Study Purpose

- Determine if the Project may have a significant effect on the environment and basis for deciding what type of environmental document to prepare
- Focuses the EIR on the effects determined to be potentially significant
- Identifies the effects determined not to be significant

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Initial Study Scope

Environmental Factors Analyzed

- Aesthetics
- Air Quality
- Cultural Resources
- Geology and Soils
- Hazards and Hazardous Materials
- Land Use and Planning
- Noise
- Public Services
- Socioeconomics
- Tribal Cultural Resources
- Agriculture and Forestry Resources
- Biological Resources
- Environmental Justice
- Greenhouse Gases
- Hydrology and Water Quality
- Mineral Resources
- Population and Housing
- Recreation
- Transportation and Traffic
- Utilities and Services Systems

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Initial Study Results

Proposed for Further Analysis in EIR

- Aesthetics
- Air Quality
- Geology and Soils
- Greenhouse Gases
- Hazards and Hazardous Materials
- Hydrology and Water Quality
- Noise
- Transportation and Traffic
- Tribal Cultural Resources

Currently Excluded from Further Analysis in EIR

- Agriculture and Forestry Resources
- Biological Resources
- Cultural Resources
- Environmental Justice
- Land Use and Planning
- Mineral Resources
- Population and Housing
- Public Services
- Recreation
- Socioeconomics
- Utilities and Services Systems

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4 Public comment

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Public Comment

- Ensure public disclosure and participation
  - Fill out speaker card
  - Each speaker is limited to **3 minutes**
  - State your name and address for the record
  - Oral public comments will be recorded by court reporter
  - Comment letter/form

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5 Closing Remarks

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CEQA Review Process

- Public participation opportunities
  - Notice of Preparation
  - Scoping meeting
  - Draft Environmental Impact Report
  - City Council Hearing

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Anticipated Schedule

Component	Timeline
Notice of Preparation/Initial Study and Public Scoping Meeting	December 2016 - January 2017
Prepare Draft EIR	February 2017 – September 2017
Responses to public comments and prepare Final EIR	Q4 2017/Q1 2018
Public hearing for EIR Certification	April/May 2018
Site Demolition	May 2018 – February 2019
Construction	February 2019 – February 2021

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Additional Information & Updates

http://Graysonrepowering.com

Thank you for your participation

Stantec

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The New York Times | https://nyti.ms/2yh4CYj

WELL | LIVE

Air Pollution Tied to Kidney Disease

By NICHOLAS BAKALAR SEPT. 21, 2017

Add a new potential ill to the list of problems linked to air pollution: kidney disease.

Previous studies have linked high levels of the fine particulate matter known as PM 2.5 to cardiovascular disease and stroke. A new analysis, in The Journal of the American Society of Nephrology, followed 2,482,737 veterans for an average of eight and a half years. The Department of Veterans Affairs database includes information on glomerular filtration rate, or G.F.R., a measure of kidney function.

Using data on air pollution from NASA and the Environmental Protection Agency, the researchers found that increases in PM 2.5 corresponded directly with decreases in G.F.R., indicating worsening kidney function. PM 2.5 particles are small enough to enter the bloodstream where they make their way to the kidneys, which are especially prone to injury from pollutants.

The scientists calculate that “unhealthy” pollution levels lead to an annual increase of 44,793 cases of chronic kidney disease, and 2,438 cases of end-stage kidney disease requiring dialysis. Even levels below those considered “safe” increased risk.

The senior author, Dr. Ziyad Al-Aly, an assistant professor of medicine at Washington University in St. Louis, said that diabetes and hypertension are still the major drivers of kidney disease. But, he said, “Air pollution is a previously unrecognized factor for kidney disease and kidney disease progression.”

9
ARTICLES REMAINING
SEE MY OPTIONS

A version of this article appears in print on Septembe 26, 2017, on Page D4 of the New York Edition with the headline: Risks: Dirty Air and Kidney Disease.

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9
ARTICLES REMAINING

SEE MY OPTIONS

The surprising link between air pollution and Alzheimer's disease

The cognitive effects of pollution are more pronounced in women who carry APOE-e4. (Feb. 1, 2017)

By **Melissa Healy**

JANUARY 31, 2017, 6:50 PM

With environmental regulations expected to come under heavy fire from the Trump administration, new research offers powerful evidence of a link between air pollution and dementia risk.

For older women, breathing air that is heavily polluted by vehicle exhaust and other sources of fine particulates nearly doubles the likelihood of developing dementia, finds a study published Tuesday. And the cognitive effects of air pollution are dramatically more pronounced in women who carry a genetic variant, known as APOE-e4, which puts them at higher risk for developing Alzheimer's disease.

In a nationwide study that tracked the cognitive health of women between the ages of 65 and 79 for 10 years, those who had the APOE-e4 variant were nearly three times more likely to develop dementia if they were exposed to high levels of air pollution than APOE-e4 carriers who were not.

Among carriers of that gene, older women exposed to heavy air pollution were close to four times likelier than those who breathed mostly clean air to develop "global cognitive decline" — a measurable loss of memory and reasoning skills short of dementia.

While scientists have long tallied the health costs of air pollution in asthma, lung disease and cardiovascular disease, the impact of air pollutants on brain health has only begun to come to light. This study gleans new insights into how, and how powerfully, a key component of urban smog scrambles the aging brain.

Published Tuesday in the journal Translational Psychiatry, the research looks at a large population of American women, at lab mice, and at brain tissue in petri dishes to establish a link between serious cognitive decline and the very fine particles of pollution emitted by motor vehicles, power plants and the burning of biomass products such as wood.

All three of these biomedical research methods suggest that exposure to high levels of fine air pollutants increases both dementia's classic behavioral signs of disorientation and memory loss as well as its less obvious hallmarks. These include amyloid beta protein clumps in the brain and the die-off of cells in the brain's hippocampus, a key center for memory formation.

Using air pollution standards set by the U.S. Environmental Protection Agency, researchers found significant differences on all those measures between those who breathed clean air and those exposed to pollution levels deemed unsafe.

In lab mice, breathing air collected over the 10 Freeway in Los Angeles led to brain concentrations of amyloid protein that were more dense and more likely to form dangerous clumps than breathing air that satisfied EPA standards before 2012. When lab mice were bred with a strong predisposition to develop dementia and its hallmarks, the brain differences between pollution-breathing animals and those that breathed clean air were starker.

In 2011, a study in the journal Lancet found that those who lived close to densely trafficked roads were at a far higher risk of stroke and dementia than those who lived farther away. A year later, a team led by Alzheimer's disease researcher Dr. Samuel Gandy at Mt. Sinai in New York first established that air pollutants induced inflammation, cell death and the buildup of amyloid protein in the brains of mice.

The new study extends those findings.

Authored by geriatric and environmental health specialists at USC, the new study estimates that before the EPA set new air pollution standards in 2012, some 21% of new cases of dementia and of accelerated cognitive decline could likely have been attributed to air pollution.

There is potential legal significance to the researchers' finding that women (and mice) who carried a genetic predisposition to developing Alzheimer's disease were far more sensitive to air pollution's effects. In devising pollution standards, the EPA is currently required to consider their health impact on "vulnerable populations." The agency is also required to use its regulatory authority to take steps to protect those populations.

Air pollution has been declining steadily since the EPA promulgated new standards in 2012. But Dr. Jiu-Chiuan Chen, an environmental health specialist at USC's Keck School of Medicine and the study's senior author, said it's not clear that even current standards are safe for aging brains, or for brains that are genetically vulnerable to Alzheimer's.

The Trump administration has signaled it will look to scrap or substantially rewrite Obama administration regulations that tightened emissions from power plants and established tougher fuel efficiency standards for cars in an effort to curb climate change and reduce air pollution.

"If people in the current administration are trying to reduce the cost of treating diseases, including dementia, then they should know that relaxing the Clean Air Act regulations will do the opposite," Chen said.

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This article is related to: Environmental Science, Medical Research, Scientific Research, Alzheimer's Disease, U.S. Environmental Protection Agency

Power Plant Built in Open: Glendale Will Have First Completely Qu
Los Angeles Times (1923-Current File); Jun 30, 1940;
ProQuest Historical Newspapers: Los Angeles Times
pg. A10

Power Plant Built in Open

Glendale Will Have First Completely Quake-proof Setup

With much of its equipment tc be installed in the open air, Glendale is erecting the world's first completely earthquake-proof light plant, it was disclosed yesterday. The new $1,800,000 steam generating plant is approaching completion at San Fernando Road and Kellogg Ave.

Among unique features is the location of the huge turbo-generator on an uncovered open deck. A special metal cover will protect the generator from rain and dust. The only building is a shell built of light steel and stucco filler walls which will hide the more or less unsightly appearance of boilers. A 22-foot-deep basement of heavily reinforced concrete rests on concrete piling.

Prof. R. R. Martel of the California Institute of Technology, national authority on earthquake-proofing buildings, assisted Peter Diederich, Glendale public service superintendent, in the pioneering outdoor design.

Elks to Entertain Band

The Sheriff's Boys Band of 100 pieces will be guests of the B.P.O. Elks in an Americanism program to celebrate the birth of Independence Day at Elks Temple Wednesday night, July 3, it is announced by Exalted Ruler Jere J. Sullivan.

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Mexico City residents whose buildings survived the 1985 quake thought they'd be safe in the next big one. They were wrong

Many in Mexico believed structures that survived the 1985 earthquake were safe. (Sept. 21, 2017)

By **Laura Tillman and Rong-Gong Lin II**

SEPTEMBER 20, 2017, 4:00 PM | REPORTING FROM MEXICO CITY

Even in one of the most earthquake-prone cities in the world, Peniley Ramirez never felt in danger inside her apartment. The seven-story building in the Roma neighborhood had survived the devastating Mexico City quake of 1985, which killed thousands.

“People said it was perfect during ’85, there was no damage at all, so we always felt safe,” she said.

But after Tuesday’s earthquake, neighbors had to break down her door with a pickax to get her out.

The building was leaning and in danger of collapsing. Still, on Wednesday morning her husband and volunteers managed to retrieve paintings, toys, clothes and the television.

“I don’t know if I want to live in the Tower of Pisa,” said Ramirez, a reporter for Univision.

It was a widespread belief in Mexico City: If your house or apartment building was still standing after Sept. 19, 1985 — perhaps the most infamous date in the city’s modern history — it would withstand the next big quake. That theory was put to the test this week. It was wrong.

Experts have long understood that history is an unreliable guide when it comes to how a building will fare in an earthquake, whether in Mexico, California or any other place criss-crossed by fault lines.

“This earthquake proved it: Doing well in one earthquake doesn’t mean you’ll do well in the next earthquake,” said Kit Miyamoto, a member of the California Seismic Safety Commission and chief executive of the structural engineering firm Miyamoto International. “Because every earthquake is different. And every building responds differently.”

Although Tuesday’s magnitude 7.1 earthquake was far weaker than the magnitude 8 temblor of 1985, its epicenter was much closer to Mexico City — 80 miles away, compared with 250.

That, experts said, largely explains the damage pattern emerging in preliminary reports: shorter, older buildings that were spared in 1985 were especially vulnerable this time, while taller buildings fared much better than they did a generation ago.

In videos taken during the earthquake and moments after, dust clouds hover over shorter, older buildings while taller ones sway violently but remain standing. The school south of downtown where at least 25 children were killed was three stories.

Why shorter and taller buildings can react differently in the same earthquake is a matter of physics — like a wineglass that shatters when subjected to the vibration of a particular musical note.

Mega-earthquakes, such as the one in 1985, are caused by extremely long faults. They produce low, booming shaking frequencies that can travel for vast distances — think of the bass beat you might hear from a distant rave — and produce the sensation of rolling motion, like the kind you might feel on a boat. Tall buildings are particularly vulnerable to this kind of motion.

That is particularly true in Mexico City, which sits on an ancient lake bed. Its soft soils amplify the shaking from an earthquake by 100 times, said Lucy Jones, a seismologist and former science advisor for risk reduction at the U.S. Geological Survey.

Moreover, the lake bed is believed to have a natural resonant frequency that was activated in the 1985 earthquake and targets buildings that are between five and 20 stories — the very buildings that

suffered the most damage in that disaster, which killed at least 4,200 people and by some estimates many more.

Something similar happened in the 2015 magnitude 7.8 Nepal earthquake, in which Katmandu, which also sits on an ancient lake bed, saw its tall buildings suffer damage, while its short buildings performed far better.

By contrast, short buildings are most vulnerable when they are close to the epicenter, which produces a shaking often described as herky-jerky, or having sudden, intense up-and-down or side-to-side movement. That high-frequency movement is not felt farther away from an earthquake's source.

The 1985 quake therefore spared smaller buildings, many of them made of brick or brittle concrete that was long a staple of construction in Mexico, without much steel reinforcement that newer building codes require to protect against earthquakes.

This time the owners and occupants of some of those buildings were not so fortunate.

"The buildings that collapsed — most of them were very old buildings. Most of the buildings are maybe five, six stories," said Guillermo Lozano, an aid worker with the humanitarian organization World Vision Mexico.

"There's a feeling that this city after 1985 was not vulnerable," he said. "And that's true in one way, because the new buildings, most of the new buildings were not affected. They're OK. They had good protocols. People knew what to do. But what about the old buildings?"

Keith Dannemiller, a freelance photographer who has lived in Mexico for decades, said he had long subscribed to the theory that pre-1985 structures were battle-tested.

But in recent years, he had started to wonder whether the smaller quakes that are common here were taking a toll on structures such as the six-story apartment building where he lives with his wife in the stylish — and aging — Condesa neighborhood.

Built in 1968, it suffered serious damage Tuesday, raining chunks of concrete and brick inside his apartment.

If the building proves uninhabitable, he said, he might look into renting an apartment constructed in the 1990s or later.

"Maybe the Condesa has lost a little glimmer and shine because of this," he said.

Nearby in the Roma neighborhood, Mariana Dieguez, a 21-year-old dental student, stood outside a commercial building that had collapsed and killed a child on the sidewalk.

“Most of the ones falling are older,” she said. “The ones built after ’85 have done well.”

Constructed in the 1950s, the four-story building is now a mountain of concrete chunks and steel.

Dieguez had come to help in the rescue effort, joining a crowd of volunteers equipped with shovels, masks and gloves. But soldiers stationed there said it was too dangerous and turned them away, drawing angry shouts.

One of the volunteers, 25-year-old Ismael Alejandro Monroy Montesinos, explained why he had come to help: “This happened to our parents and now it’s happening to today’s generation.”

Special correspondent Laura Tillman reported from Mexico City and Times staff writer Lin from San Francisco.

ron.lin@latimes.com

ALSO

How to help Mexico's earthquake victims

Death toll from Mexico's earthquake climbs to 230 as frantic search continues for survivors

Could your building collapse in a major L.A. earthquake? Look up your address on these databases

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This article is related to: Earthquakes

California could be hit by an 8.2 mega-earthquake, and it would be catastrophic

By **Rong-Gong Lin II**

SEPTEMBER 19, 2017, 4:20 PM

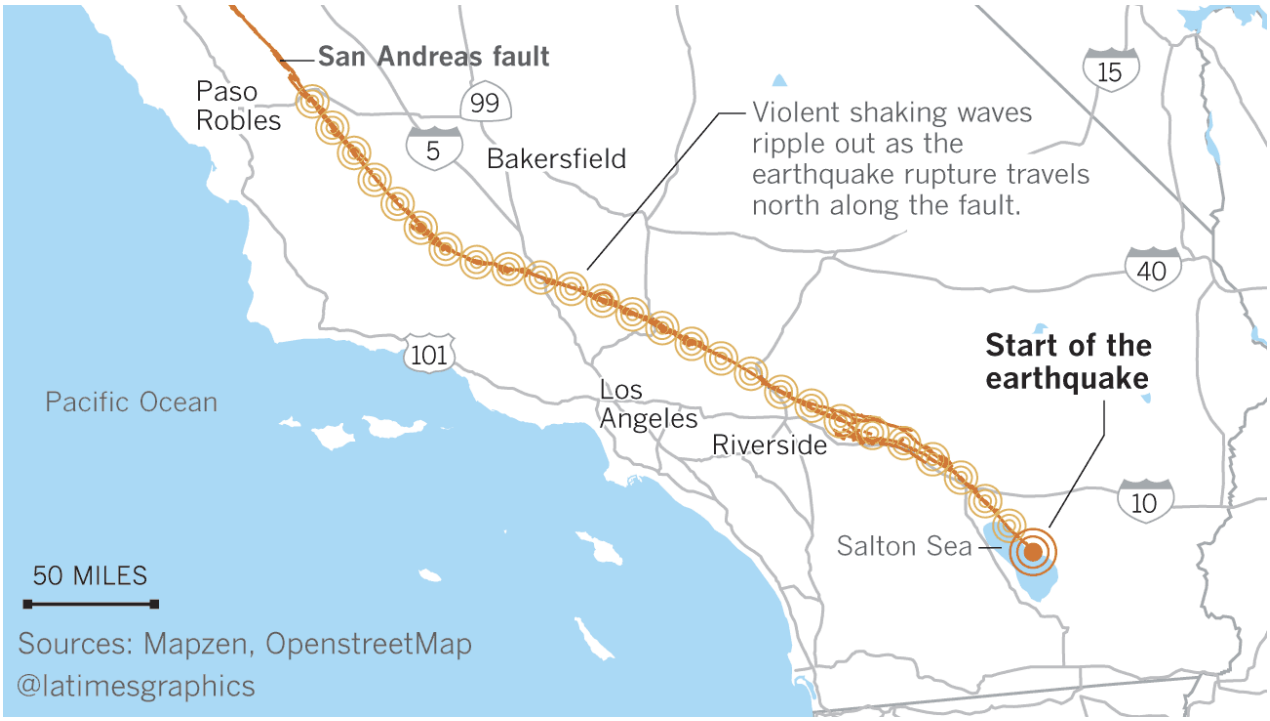
The magnitude 8.2 earthquake that ravaged southern Mexico on Sept. 7 was the largest to shake the country in nearly a century.

Like California, Mexico is a seismically active region that has seen smaller quakes that have caused death and destruction. But the Sept. 7 temblor is a reminder that even larger quakes — while rare — do occur.

Scientists say it's possible for Southern California to be hit by a magnitude 8.2 earthquake. Such a quake would be far more destructive to the Los Angeles area because the San Andreas fault runs very close to and underneath densely populated areas.

The devastating quakes that hit California over the last century were far smaller than the Sept. 7 temblor, which Mexican authorities set at magnitude 8.2 and the U.S. Geological Survey placed at 8.1. Mexico's earthquake produced four times more energy than the great 1906 San Francisco earthquake, a magnitude 7.8, which killed 3,000 people and sparked a fire that left much of the city in ruins.

Southern California's most recent mega-quake was in 1857, also estimated to be magnitude 7.8, when the area was sparsely populated. (That was considerably stronger than the 7.1 quake that hit Mexico on Tuesday, causing buildings to collapse and leading to a significant loss of life).



Here's what a hypothetical magnitude 8.2 earthquake would look like in Southern California -- a quake that begins near the Mexican border and moves north and west through L.A. County into central California. (Los Angeles Times)

A magnitude 8.2 earthquake would rupture the San Andreas fault from the Salton Sea — close to the Mexican border — all the way to Monterey County. The fault would rupture through counties including Los Angeles, Riverside and San Bernardino.

An 8.2 earthquake would be far worse here because the San Andreas fault runs right through areas such as the Coachella Valley — home to Palm Springs — and the San Bernardino Valley, along with the San Gabriel Mountains north of Los Angeles. The fault is about 30 miles from downtown Los Angeles.

The Sept. 7 earthquake occurred in the ocean off the Mexican coast and began about 450 miles from Mexico City — and it was relatively deep, starting about 43 miles under the surface.

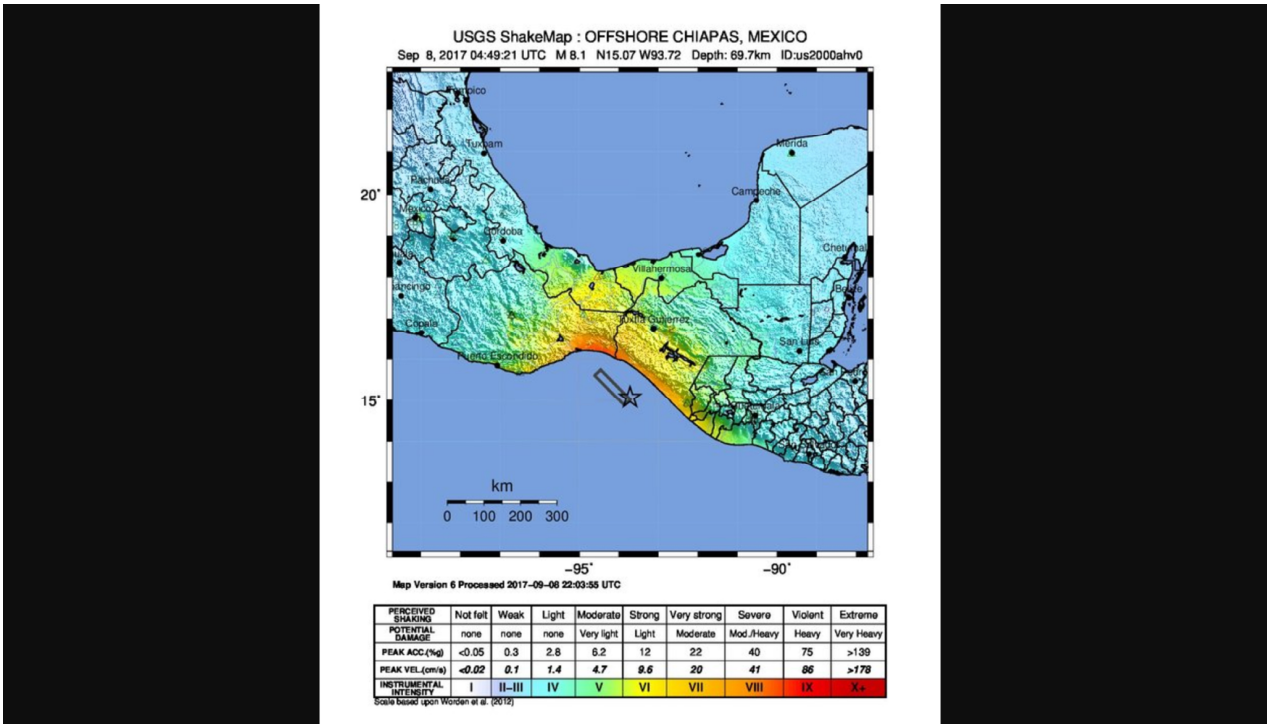
In Mexico, “you’ve got [many] people a pretty long way aways from it,” seismologist Lucy Jones said. But in Southern California, “we’d have a lot of people right on top of it. It would be shallow, and it runs through our backyard.”

A magnitude 8.2 on the San Andreas fault would cause damage in every city in Southern California, Jones has said, from Palm Springs to San Luis Obispo.

WORSE SHAKING THAN NORTHRIDGE

Intense shaking would be worse

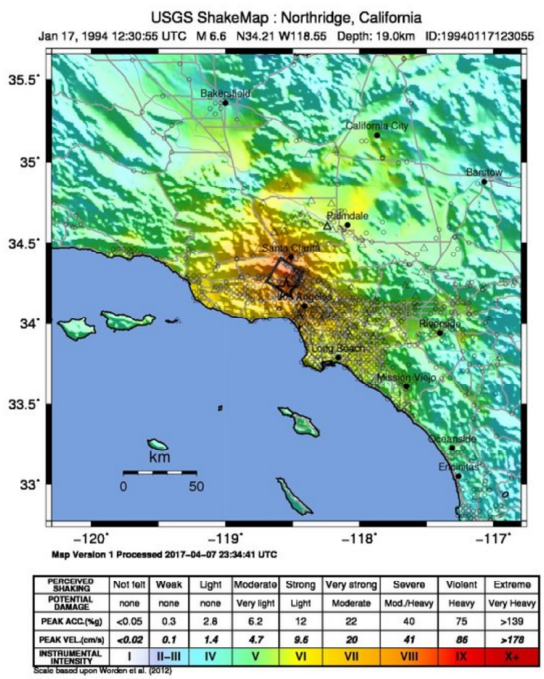
Southern California would feel even worse shaking if a magnitude 8.2 earthquake hit here than what was experienced in Mexico on Sept. 7. Mexico's earthquake struck under the ocean and was deep; "violent" shaking — calculated as intensity 9 shaking by the USGS — struck only a relatively small part of the country that happens to be sparsely populated.



The worst shaking intensity felt on land was intensity level 9, or "violent" shaking, shown in red in this map of Thursday's south Mexico earthquake. The epicenter is noted by the star, and the area of fault that moved is represented by the rectangle. (U.S. Geological Survey)

That's the same intensity that was felt in the worst-hit neighborhood in the 1994 magnitude 6.7 Northridge earthquake.

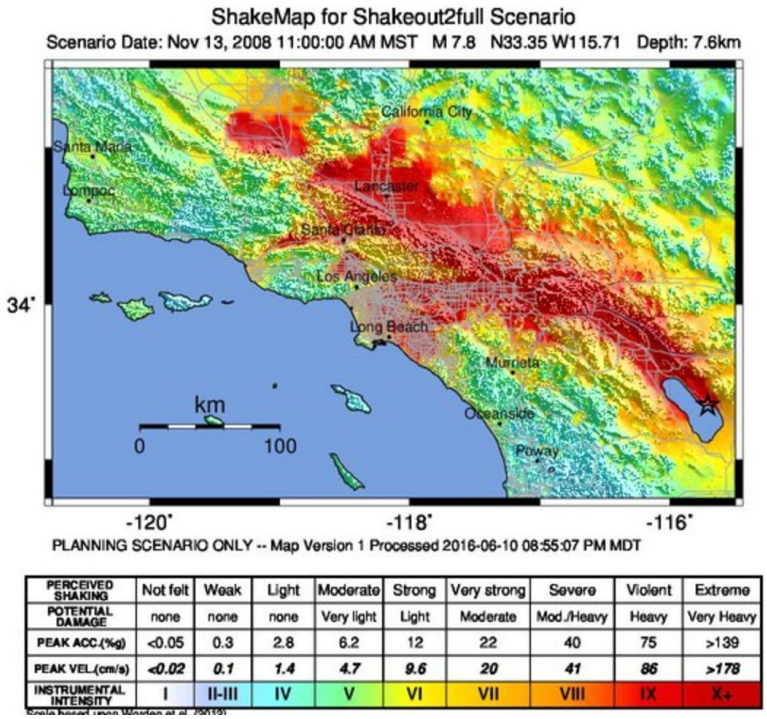
Even though the Northridge and Mexico seismic events vary widely in magnitude — the Mexico earthquake on Sept. 7 produced *178 times* more total energy — Angelenos also felt "violent" shaking in 1994 because the Northridge earthquake struck directly underneath heavily populated areas and was extremely shallow, striking between just four and 12 miles under the surface.



The magnitude 6.7 Northridge earthquake in 1994 produced intensity level 9 shaking — violent shaking — in a small section of the San Fernando Valley. (U.S. Geological Survey)

A magnitude 8.2 earthquake on the San Andreas would produce shaking more intense than either the Mexico or Northridge earthquakes.

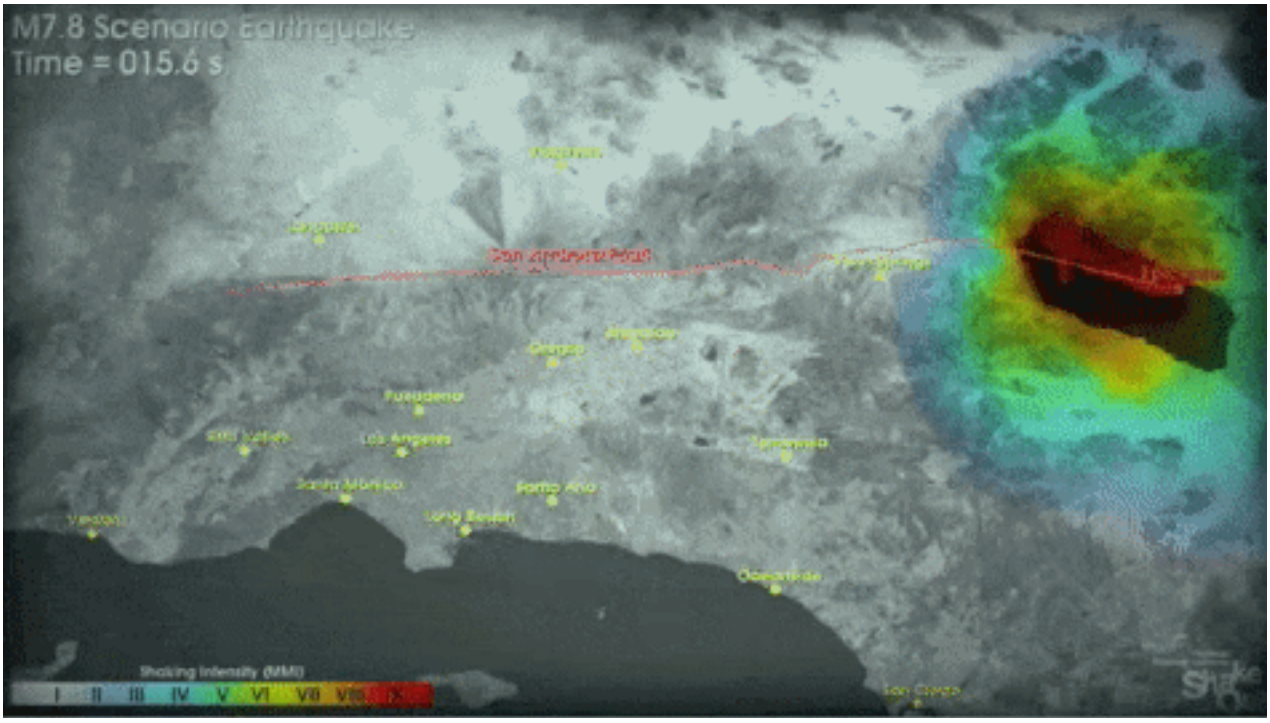
It would bring intensity level 10 shaking, which is perceived by humans as "extreme." Such shaking would blanket huge swaths of Southern California — an earthquake that no one alive today has experienced in this region.



PERCEIVED SHAKING	Not felt	Weak	Light	Moderate	Strong	Very strong	Severe	Violent	Extreme
POTENTIAL DAMAGE	none	none	none	Very light	Light	Moderate	Mod./Heavy	Heavy	Very Heavy
PEAK ACC.(%g)	<0.05	0.3	2.8	6.2	12	22	40	75	>139
PEAK VEL.(cm/s)	<0.02	0.1	1.4	4.7	9.6	20	41	86	>178
INSTRUMENTAL INTENSITY	I	II-III	IV	V	VI	VII	VIII	IX	X+

A magnitude 7.8 earthquake would bring intensity level 10 shaking — extreme shaking — to a vast area of Southern California. (U.S. Geological Survey)

The ShakeOut scenario envisioned the earthquake beginning to move the San Andreas fault at the Salton Sea close to the Mexican border, then moving rapidly to the northwest toward L.A. County.



This animation shows how intense shaking is directed from the San Andreas fault into the Los Angeles Basin. Areas of yellow indicate strong shaking; orange is "very strong" shaking and red is "violent" or "extreme" shaking, causing collapses. (U.S. Geological Survey / Southern California Earthquake Center)

Mexico City rode out the Sept. 7 earthquake better than a devastating 1985 temblor that killed thousands of people there, in large part because the capital was so far away from the epicenter of this week's quake. The capital is about double the distance from the Sept. 7 epicenter as it was from the earthquake that struck 32 years ago.

How you protect yourself when a quake hits might be all wrong »

WHAT AN 8.2 EARTHQUAKE COULD DO

A mega-earthquake in the Southland

The U.S. Geological Survey published a hypothetical scenario of what a magnitude 7.8 earthquake on the San Andreas fault would look like. The scenario is still a useful look to imagine what an 8.2 would do to much of Southern California. Both earthquakes would bring generally the same intensity of shaking to Los Angeles, but the 8.2 earthquake would send more intense shaking to areas farther north and west, such as Santa Barbara and San Luis Obispo.

Here's what could happen if it struck at 10 a.m. on a dry, calm Thursday in November, based on an earlier interview with Jones and according to the ShakeOut report:

The death toll could be one of the worst for a natural disaster in U.S. history: nearly 1,800, about the same number of people killed in Hurricane Katrina.

More than 900 could die from fire; more than 400 from the collapse of vulnerable steel-frame buildings; more than 250 from other building damage;

and more than 150 from transportation accidents, such as car crashes due to stoplights being out or broken bridges.

Los Angeles County could suffer the highest death toll, more than 1,000; followed by Orange County, with more than 350 dead; San Bernardino County, with more than 250 dead; and Riverside County, with more than 70 dead. Nearly 50,000 could be injured.

DAMAGE TO INFRASTRUCTURE

Freeways, water threatened

Main freeways to Las Vegas and Phoenix that cross the San Andreas fault would be destroyed in this scenario; Interstate 10 crosses the fault in a dozen spots, and Interstate 15 would see the roadway sliced where it crosses the fault, with one part of the roadway shifted from the other by 15 feet, Jones said.

Scared? Don't be. Here are tips on how to prepare »

“Those freeways cross the fault, and when the fault moves, they will be destroyed, period,” Jones said. “To be that earthquake, it has to move that fault, and it has to break those roads.”

The aqueducts that bring in 88% of Los Angeles’ water supply and cross the San Andreas fault all could be damaged or destroyed, Jones said.

A big threat to life would be collapsed buildings. As many as 900 unretrofitted brick buildings close to the fault could come tumbling down on occupants, pedestrians on sidewalks and even roads, crushing cars and buses in the middle of the street.

Fifty brittle concrete buildings housing 7,500 people could completely or partially collapse. Five high-rise steel buildings — of a type known to be seismically vulnerable — holding 5,000 people could completely collapse.

Some 500,000 to 1 million people could be displaced from their homes, Jones said.

Flames billow from a ruptured gas main beyond a crater in Granada Hills after the 1994 Northridge earthquake. (Los Angeles Times)

THREAT TO ELECTRICAL GRID

Southern California could be isolated

Southern California could be isolated for some time, with the region surrounded by mountains and earthquake faults. The Cajon Pass — the gap between the San Gabriel and San Bernardino mountains through which Interstate 15 is built, and the main route to Las Vegas — is also home to the San Andreas fault and a potentially explosive mix of pipelines carrying gasoline and natural gas, and overhead electricity lines.

All it would take is for the fuel line to break and a spark to create an explosion. “The explosion results in a crater,” the report says.

ShakeOut co-author Keith Porter, research professor at the University of Colorado, Boulder, warned in a 2011 study in the journal Earthquake Spectra that under certain conditions, a magnitude 7.8 earthquake could create such a sudden interruption of high-voltage interstate transmission of electricity that "potentially all of the western U.S. could lose power."

Power could be restored within hours in other states, the scenario said. But restoring power in Southern California could take several days.

There could be up to 100,000 landslides, scientists say, based off how many landslides have occurred in past magnitude 7.8 earthquakes. "The really big earthquakes ... are much more destabilizing to the hillsides," Jones said.

Patients are evacuated after a San Fernando Valley hospital collapsed in the 1971 Sylmar earthquake. (Los Angeles Times)

THREAT OF FIRE

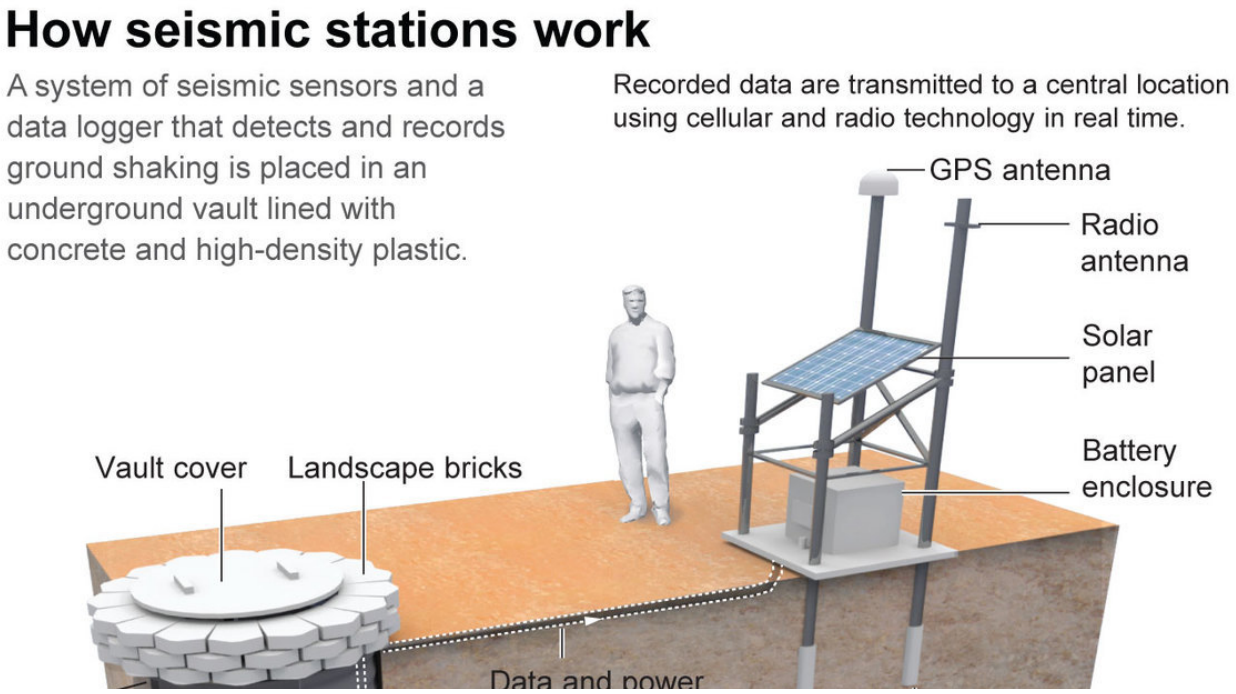
Death toll could be high in fire

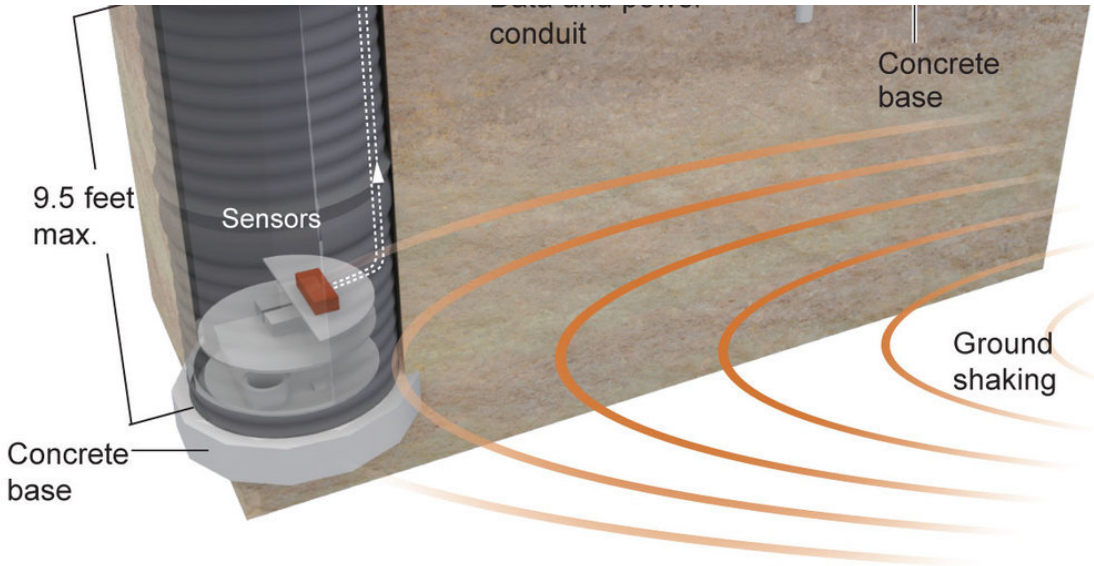
Thousands could be forced to evacuate as fires spread across Southern California; 1,200 blazes could be too large to be controlled by a single fire engine company, and firefighting efforts would be hampered by traffic gridlock and a lack of water from broken pipes. Super-fires could destroy hundreds of city blocks filled with dense clusters of wood-frame homes and apartments.

The death toll could mount as hundreds of people trapped in collapsed buildings are unable to be rescued before flames burn through. Possible locations for the conflagrations include South Los Angeles, Riverside, Santa Ana and San Bernardino.

“If the earthquake happens in [hot] weather ... or in a Santa Ana condition, the fires are going to become much more catastrophic. If it happens during a real rainy time, we’re going to have a lot more landslides,” Jones said.

Several dams could be shaken so hard that “they would be so compromised that they would require emergency evacuation,” Jones said. Even damage to just a single dam above San Bernardino could force 30,000 people out of their homes, the ShakeOut report said.





Eight-second warning for San Francisco

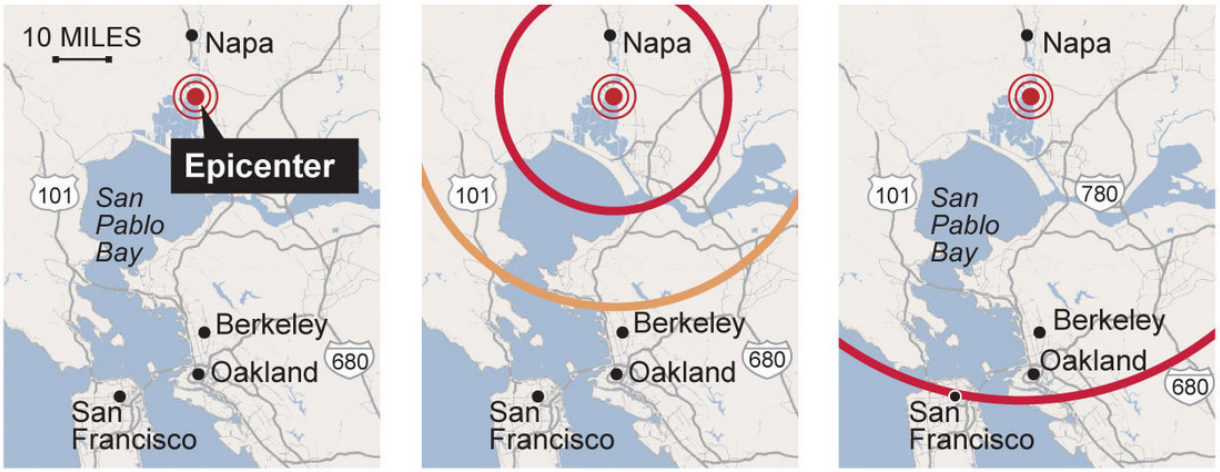
A prototype early warning system in 2014 provided San Francisco eight seconds of warning before shaking from a magnitude 6.0 earthquake in Napa began.

Initial shaking Strong shaking begins

Zero seconds
Quake begins

5.1 seconds
Early earthquake warning system sends out alert

13.1 seconds
Strong shaking begins to hit San Francisco



Sources: California Integrated Seismic Network, Caltech and U.S. Geological Survey, UC Berkeley Seismological Laboratory, OpenStreetMap, Mapbox
Graphics reporting by Rosanna Xia, Rong-Gong Lin II

@latimesgraphics

(Paul Duginski)

AN EARLY WARNING?

System could give Southern California life-saving seconds to prepare

A seismic warning system for the West Coast has been under development for years by the U.S. Geological Survey, the nation's lead earthquake monitoring agency. President Trump's budget would have ended the system before it launched. Officials were looking for "sensible and rational reductions and making hard choices to reach a balanced budget by 2027," according to the administration's proposal.

But the proposal to end the funding raised bipartisan complaints up and down the coast. Twenty-eight lawmakers in the California Legislature, including leaders from both parties, urged officials to protect the earthquake early warning system. Members of Congress from Southern California to the Canadian border say the system is crucial to public safety.

In July, a congressional committee voted to keep funding. The proposal awaits a full vote by both houses of Congress.

The earthquake early warning system works on a simple principle: The seismic waves from an earthquake travel at the speed of sound through rock — slower than today's communications systems.

For example, it would take more than a minute for a magnitude 7.8 earthquake that started at the Salton Sea to shake up Los Angeles, 150 miles away, traveling along the state's longest fault, the San Andreas.

A damaged apartment building is seen in San Francisco's Marina District after the 1989 Loma Prieta earthquake. (Jonathan Nourok / AFP/Getty Images)

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ALSO

Mexico got early warning before deadly earthquake struck. When will California get that system?

Patience in short supply as desperation sets in among South Florida residents still in Hurricane Irma's path

After Irma, calls for help from the Caribbean: 'The island is debris, that's all it is'

UPDATES:

3 p.m.: Updated with information about quake early warning system.

Sept. 19 at 2 p.m.: Updated with comparison to Tuesday's 7.1 magnitude quake.

6:50 p.m.: This article was updated to reflect that intensity 9, or "severe," shaking has been recorded in Mexico, the same level of shaking intensity felt in the worst-hit region in the Northridge earthquake.

4:45 p.m.: This article was updated with additional historical images.

This article was originally published at 3:20 p.m. on Sept. 8, 2017.

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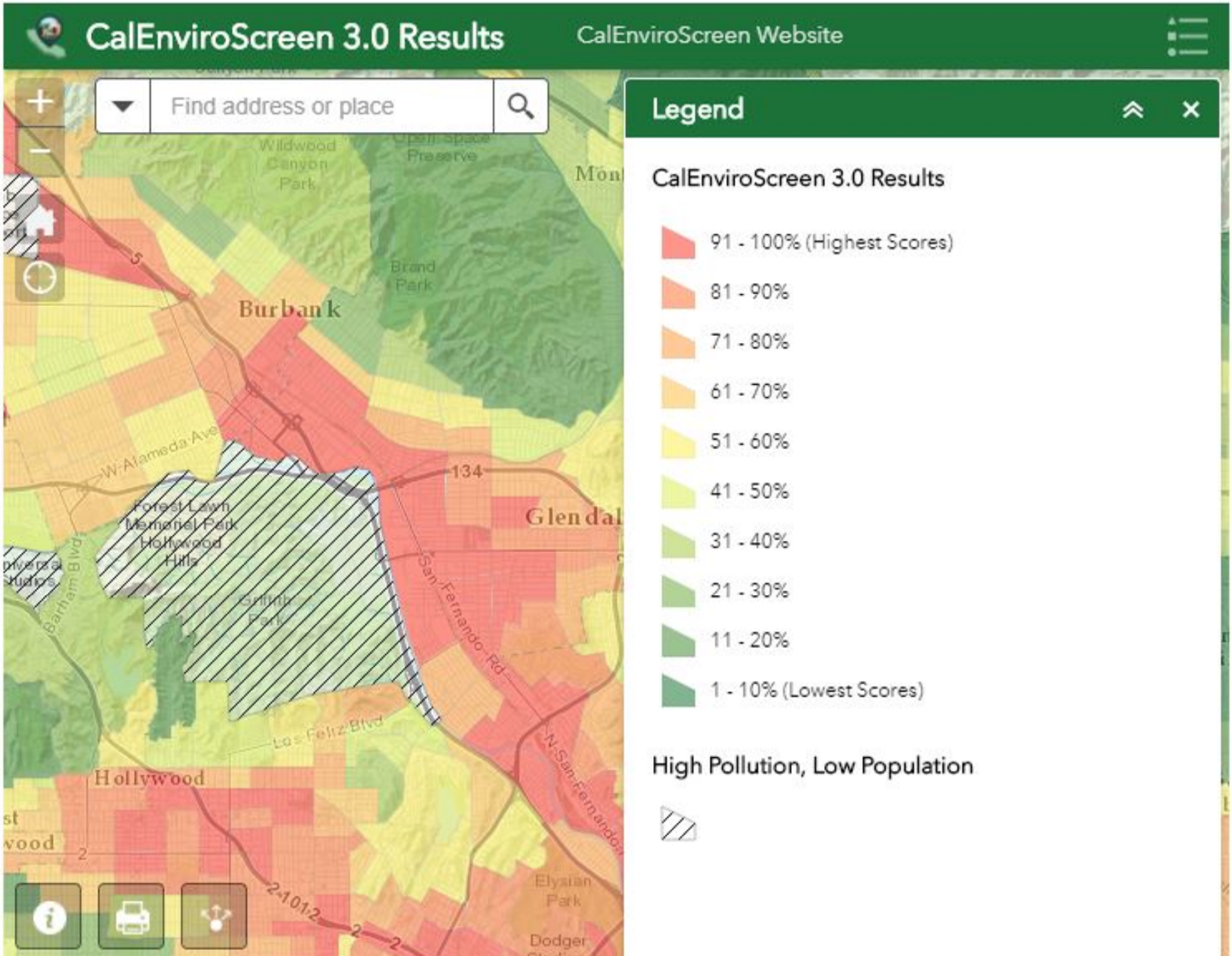
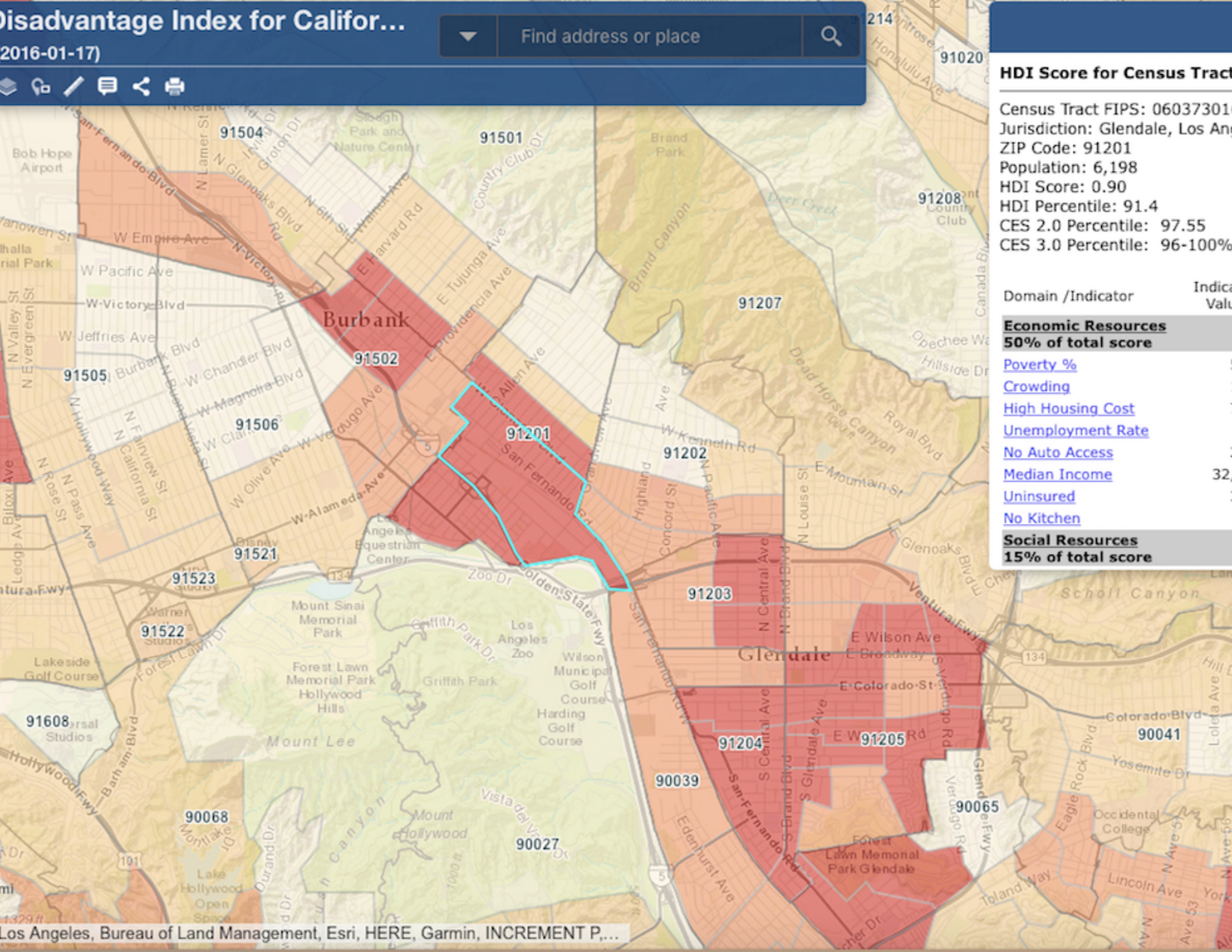
commitment to environmental justice for all.




Disadvantage Index for Califor...
(2016-01-17)
Find address or place
HDI Score for Census Tract
Census Tract FIPS: 06037301
Jurisdiction: Glendale, Los An
ZIP Code: 91201
Population: 6,198
HDI Score: 0.90
HDI Percentile: 91.4
CES 2.0 Percentile: 97.55
CES 3.0 Percentile: 96-100%
Domain /Indicator
Indica Valu
Economic Resources
50% of total score
Poverty %
Crowding
High Housing Cost
Unemployment Rate
No Auto Access
Median Income
Uninsured
No Kitchen
Social Resources
15% of total score
Burbank
Glendale
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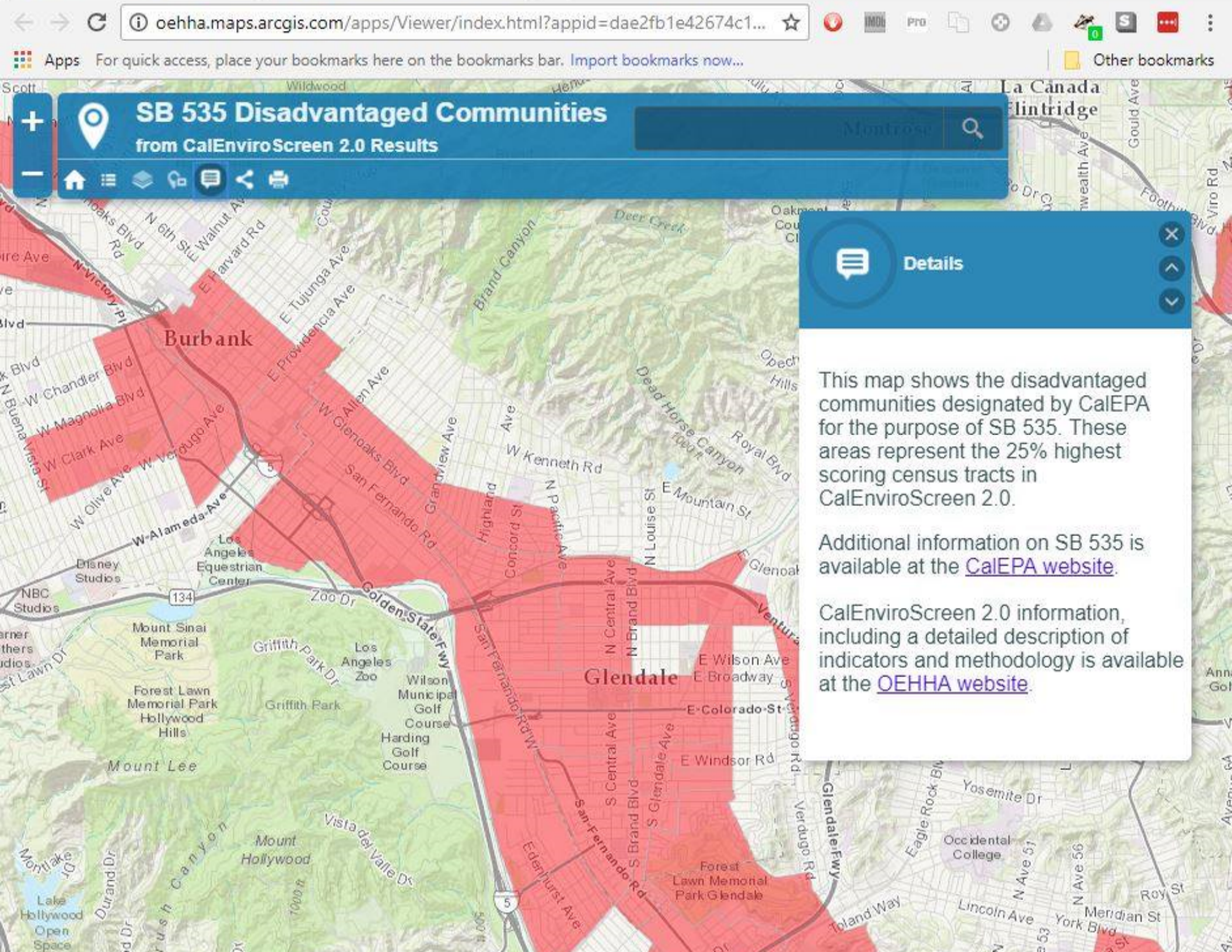
oehha.maps.arcgis.com/apps/Viewer/index.html?appid=dae2fb1e42674c1...
Apps
For quick access, place your bookmarks here on the bookmarks bar. Import bookmarks now...
Other bookmarks
SB 535 Disadvantaged Communities
from CalEnviroScreen 2.0 Results
Details
This map shows the disadvantaged communities designated by CalEPA for the purpose of SB 535. These areas represent the 25% highest scoring census tracts in CalEnviroScreen 2.0.
Additional information on SB 535 is available at the CalEPA website.
CalEnviroScreen 2.0 information, including a detailed description of indicators and methodology is available at the OEHHA website.
Burbank
Glendale
La Cañada Flintridge
Montrose
Wildwood
Mount Hollywood
Griffith Park
Los Angeles Zoo
Forest Lawn Memorial Park Glendale
Occidental College
Disney Studios
NBC Studios
Mount Sinai Memorial Park
Forest Lawn Memorial Park Hollywood Hills
Harding Golf Course
Wilson Municipal Golf Course
Los Angeles Equestrian Center
Lake Hollywood Open Space
Golden State Fwy
Glendale Fwy
San Fernando Rd
W Alameda Ave
E Colorado St
E Wilson Ave
E Broadway
E Windsor Rd
Yosemite Dr
Lincoln Ave
York Blvd
Meridian St
Toland Way
Eagle Rock Blvd
Verdugo Rd
Eden Hurst Ave
Vista del Valle Dr
Zoo Dr
Griffith Park Dr
Mount Lee
Brand Canyon
Deer Creek
Dead Horse Canyon
Royal Blvd
E Mountain St
W Kenneth Rd
W Glenoaks Blvd
W Olive Ave
W Verdugo Ave
W Clark Ave
W Magnolia Blvd
W Chandler Blvd
N Victory Pl
E Harvard Rd
E Walnut Ave
E Tujunga Ave
E Providencia Ave
W Allen Ave
Grandview Ave
Highland Ave
Concord St
N Pacific Ave
N Louise St
N Central Ave
N Brand Blvd
S Central Ave
S Brand Blvd
S Glendale Ave
Durand Dr
Montlake

978

Krause, Erik

From: Gina Briganti-Camp <gina@theselectrics.com>
Sent: Monday, November 20, 2017 9:17 AM
To: Krause, Erik
Cc: Devine, Paula; Najarian, Ara; Gharpetian, Vartan; Sinanyan, Zareh; Agajanian, Vrej
Subject: grayson re-powering project

Dear Mr. Krause,
I'm writing to express my strong opposition to the Grayson repowering project as outlined in the the September 2017 Draft EIR. 978-1
My family lives in Eagle Rock, a Glendale neighboring community, and the entire area needs to have cleaner air and better energy. This is taking a step back. 978-2
I call on the City to PAUSE the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. 978-3
This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been on the Grayson EIR.

Regards,
Gina Camp
Los Angeles, California

979

Krause, Erik

From: Gina Briganti-Camp <gina@theselectrics.com>
Sent: Monday, November 20, 2017 9:11 AM
To: Krause, Erik
Subject: Grayson repowering project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 979-1

My family lives in the neighboring Eagle Rock community and the entire area needs to have cleaner air, and better energy. This is taking a step back. 979-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 979-3

Regards,

Gina Camp
Los Angeles, (Eagle Rock neighboring Glendale)

980

Krause, Erik

From: Gina Del Grosso <gina.delgrosso@gmail.com>
Sent: Monday, November 20, 2017 3:21 PM
To: Krause, Erik
Cc: Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara; Gharpetian, Vartan
Subject: Grayson Power Plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson power plant project as outlined in the September 2017 Draft EIR. I moved to Glendale because of the wonderful schools as my daughter just started kindergarten and I love my new community and her current school. I will not however keep her here if this project moves forward as her health and wellbeing are my utmost concern. 980-1 980-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 980-3

Thank you for your attention.

Sincerely,

Gina Del Grosso
Glendale, CA

981

Krause, Erik

From: Glenn Garland <garlandglenn@sbcglobal.net>
Sent: Monday, November 20, 2017 12:36 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 981-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 981-2

Regards,

Glenn Garland
Sherman Oaks

982

Krause, Erik

From: Haikaz V. <takeahaik@yahoo.com>
Sent: Monday, November 20, 2017 1:18 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 982-1

I am sure you, like the rest of us, are a rationale human being and I understand that you are in a position of power here which you may use to serve the people and the greater good. 982-2

We all want healthier, happier lives for ourselves for our kids and for our future. In a time when other cities are committing to going 100% clean energy, it is unfathomable that a city like Glendale with its advances and progressive views and values would choose to go the opposite route. 982-3

As a voting citizen of Glendale, I urge you to work with your colleagues to come up with a better plan for our city, for our citizens and for ourselves. Let's go green. Let's keep our air clean. Let's have fresh oxygen to breathe. After all, what is the purpose of being on this planet if we spend it poisoning our minds and bodies with toxins? Are we here to encourage pollution and promote disease or do we work to prevent and even reverse these things? 982-4

Regardless of special interests, or the "powers" that may be, or big money, or lobbyists, or big oil or whoever else, the true power lies in the people. I'm sure you know the choice is clear here. Please, do us all a favor, listen to you conscience and have the courage, bravery and persistence to put a stop to this and come up with a better plan that benefits all. Yes, we need power, yes we need revenue, but YES there are also better ways to do this. Let's invest in our future by doing the hard and intelligent work that is required of us today. 982-5

Please and thank You :)

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 982-6

Regards,

Haikaz V.
A voting resident of in Glendale, CA

983

Krause, Erik

From: Hana Ardelean <hanashirley@gmail.com>
Sent: Monday, November 20, 2017 8:12 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Please STOP the Grayson Repowering Project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 983-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 983-2

Regards,
Hana Ardelean

--

w: tigertigerstudio.com

984

Krause, Erik

From: Scheetz, Hank <ScheetzH@metro.net>
Sent: Monday, November 20, 2017 7:14 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 984-1

I think the City's plan is very short sighted and with all of the renewable options should have included much more research into including renewable energy alternatives in the plan. Considering California's efforts to be in the forefront in requiring rapid transition to using newer, less polluting, options, it seems like the City of Glendale is making a less aggressive commitment that will have long term negative effects environmentally and economically. 984-2

Now is the time for our City leaders to step back and relook at this decision. Let's try actually Leading. 984-3

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 984-4

Respectfully,

Hank Scheetz
Resident, City of Glendale, California

985

Krause, Erik

From: Earthjustice <action@earthjustice.org> on behalf of Hans gÃ?nther <info@earthjustice.org>
Sent: Monday, November 20, 2017 6:08 AM
To: Krause, Erik
Subject: Please reject plants to rebuild the Grayson natural gas power plant

Nov 20, 2017

Deputy Director of Community Development Erik Krause

Dear Deputy Director of Community Development Krause,

please stand against this,

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson natural gas power plant in favor of clean energy alternatives. 985-1

Thousands of people live and work directly within the Grayson project's impact zone, which includes schools, daycare centers, homes for the elderly and offices. Glendale's air quality is already terrible--it's time to invest in an energy grid that can turn that around. 985-2

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the city has enough energy to cover our daily needs most of the time. Our summertime spikes can be met with clean energy, just as other communities around California are doing.
The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. 985-3

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power and we can too. It's time for Glendale to step into a clean air, clean energy future. 985-4

Sincerely,

Hans gÃ¼nther

Glendale, AZ 85305-3171
the-green-hornet@outlook.de

986

Krause, Erik

From: Heather Matula <heathermatula@gmail.com>
Sent: Monday, November 20, 2017 9:42 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 986-1

Although I live in LA, my children go to school in Glendale and we are considering purchasing a home in Glendale. This significantly impacts my family & I would make choices based on the outcome. 986-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 986-3

Regards,

Heather Matula, Los Angeles

987

Krause, Erik

From: Heather McCallum <himccallum@gmail.com>
Sent: Monday, November 20, 2017 8:42 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 987-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 987-2

Regards,
Heather McCallum
Glendale, CA

--

Heather McCallum

323-308-8333

988

Krause, Erik

From: Heather McCallum <himccallum@gmail.com>
Sent: Monday, November 20, 2017 8:35 AM
To: Krause, Erik
Cc: Devine, Paula; Najarian, Ara; Sinanyan, Zareh; Agajanian, Vrej; Gharpetian, Vartan
Subject: Stop Grayson Power Plant!

Good Morning Mr. Krause and City Council Members,

As a concerned citizen of Glendale I am writing to tell you that I am extremely against and the Grayson power plant expansion and dangerous hazards it will have on our community. I am asking for a TRULY independent study of clean energy alternatives. In the year 2017 we should definitely not be putting money or energy into anything other than clean renewables. 988-1

I TRULY hope you all consider how worried people are about this and to think of the future and the effect not only on the community, but the planet as a whole. 988-2

Thank you for your time.

--

Heather McCallum

323-308-8333

989

Krause, Erik

From: Heidi Miller <hideemiller@gmail.com>
Sent: Monday, November 20, 2017 9:58 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 989-1

Quality of air impacts quality of life. Our kids deserve to grow up in a healthy environment. The Grayson repowering project will simply add more pollution to our air. 989-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 989-3

Regards,

Heidi Miller
Burbank

990

Krause, Erik

From: helenesvideo@sbcglobal.net
Sent: Monday, November 20, 2017 1:53 AM
To: Krause, Erik
Subject: Glendale Power Plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 990-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 990-2

Regards,

Helen L. Glavey, Glassell Park

Sent from Yahoo Mail on Android

991

Krause, Erik

From: Helene Kress <aktorchick@yahoo.com>
Sent: Monday, November 20, 2017 1:46 AM
To: Krause, Erik
Subject: Glendale Power Plant

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 991-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 991-2

Regards,

Helene Kress, Glassell Park

Sent from Yahoo Mail on Android

992

Krause, Erik

From: jack cusumano <jack.cusumano@gmail.com>
Sent: Monday, November 20, 2017 3:55 PM
To: Krause, Erik
Subject: Grayson Repowering Project

Dear Mr. Krause,

My name is Jack Cusumano, and I live just about a mile away from Grayson.

My wife and I live across the street from Franklin Elementary with our daughter, who is likely to attend Franklin when she starts school in a couple years. I work at Disney on Sonora, which is only a few blocks from home (and Grayson), and love to take my daughter to play in the Griffith Manor Park, which is right by Grayson as well. 992-1

If this project goes through, myself and my family will be exposed to the worsened air quality almost all of the time - at home, at school and at work - so it is extremely important to me that this project does not go ahead in its proposed form. My daughter is only 20 months old, and it breaks my heart if she has to start her life exposed to additional air pollutants that could harm her growth and put her at risk for serious health problems down the road, all at the beginning of her life. 992-2

Not only would this project subject us to increased pollutants in the air during almost all of our daily lives (home, work, and school), it's just an impractical waste of money for Glendale. It will be obsolete and unable to be used by 2045, at the latest, which is well under the amount of years the parts are able to operate for, so we're paying for decades more use than we're even getting. 992-3

Furthermore, the amount of power it would generate is well over the amount we need for our city, and usage is expected to go down in the future, not up, so why pay for an outrageous power capacity when we will use less and less power as technologies advance? 992-4

This project strikes me as an industry that knows its days are numbered (fossil fuel burning tech) scrambling to make a huge, overpriced sale before the wheels fall off and their tech becomes worthless. Don't get duped into buying it! 992-5

For my family's sake I am imploring you to please not greenlight this wasteful, shortsighted and harmful plan. Think with your heart and act for the families that live, work, learn and play in this area, and think with your wallet and don't waste our city's money! 992-6

Thank you,
Jack Cusumano

993

Krause, Erik

From: Jacob Robinson <jacobsrobinson@gmail.com>
Sent: Monday, November 20, 2017 3:25 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 993-1

With a child on the way, our pollution level is more important than ever to us. 993-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 993-3

Regards,

Jacob Robinson, Glendale

Sent from my iPhone

994

Krause, Erik

From: James Eowan <james.eowan@gmail.com>
Sent: Monday, November 20, 2017 11:09 AM
To: Krause, Erik; Devine, Paula; Najarian, Ara; Agajanian, Vrej; Gharpetian, Vartan; Sinanyan, Zareh
Subject: Grayson Repowering Project

Mr. Krause,

Along with so many of my neighbors, colleagues, friends and family who are born, live, age, work, learn and play in Glendale and surrounding communities, I am writing to voice my strong opposition to the repowering project as detailed in the September draft EIR. 994-1

I know that you are aware of the extensive potential negative results of the expansion, including increased pollution, lowered property values, and instability of the plant in the event of a natural disaster. Those issues deserve real consideration and independent review. 994-2

I believe that Glendale has the chance to situate itself at the forefront of public decision-making as we move into a new era of climate change. I've been so delighted with the forward-thinking policies that have taken effect in our city. The quality of my children's lives are improved every day by things like smoking policies, public art, and diverse educational programming. Why not let Glendale lead the way with reduction of fossil fuel use rather than doubling down on dirty power? 994-3

I have been a proud Glendale resident and homeowner for nearly 15 years. My oldest child attends school around the corner from Grayson and my two other children attend preschool not too far away. I am fearful of and disappointed by the current plans, which will compromise the health of city and neighboring residents in the name of increased revenue. 994-4

Please take this moment to pause the CEQA process and commission an independent study of clean alternatives for our city. Please take this moment to ensure that the process is transparent, science-based, and democratic. And above all, please take this moment to prioritize the well-being of our community. 994-5

Thank you for your consideration.

James Eowan

995

Krause, Erik

From: Jamie Sperling <jamie.schiff@gmail.com>
Sent: Monday, November 20, 2017 11:12 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: OPPOSITION

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 995-1

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 995-2

Regards,

Jamie Sperling, Burbank resident

jamie.schiff@gmail.com
323-337-4032

996

Krause, Erik

From: Lanigan <lanifam@gmail.com>
Sent: Monday, November 20, 2017 9:45 AM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Fwd: GWP

Why is Glendale Water and Power planning on expanding their natural gas plant which will emit 7 times more emissions than it currently produces -- raising toxic air particulate levels 542% which cause cancer and asthma and impaired neurological function in children -- when the City of Los Angeles is looking into running their city on renewable energy? 996-1

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 996-2

My granddaughter represents the 6th generation of my family to live in the Glendale area and she deserves a long healthy future in our home town, as do we all. 996-3

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 996-4

Regards,

Jana Lanigan
La Crescenta/Glendale, CA

997

Krause, Erik

From: JASON MOSS <jmo6@me.com>
Sent: Monday, November 20, 2017 7:26 AM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: Grayson EIR

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 997-1

[Personalized text] – feel free to draw on your experience or any of the points in the talking points

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 997-2

Regards,
Jmo @ Glendale

998

Krause, Erik

From: Javeed <shaikjadoo@hotmail.com>
Sent: Monday, November 20, 2017 2:37 PM
To: Krause, Erik
Cc: Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 998-1

As a Father living in Glendale to a small child and another on the way, I am truly disappointed that our city who has 'pledged' to be more green is resorting to old technology solutions to re-power Grayson. California is trying to lead the way in the country and in the world in using cleaner energy and committing to lowering our impact in Climate Change. 998-2

Lets act like Californians here in Glendale, and lets use this opportunity to be an example for other cities in the state to show how it is possible to do our part to clean our air with the implementation of renewable energy technology right here in our own city. 998-3

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 998-4

sincerely,

Javeed, 91201 Glendale

Sent via the Samsung Galaxy S7 edge, an AT&T 4G LTE smartphone

999

Krause, Erik

From: jean-charles galiana <jeancharlesgaliana@yahoo.com>
Sent: Monday, November 20, 2017 4:10 PM
To: Krause, Erik; Gharpetian, Vartan; Devine, Paula; Agajanian, Vrej; Sinanyan, Zareh; Najarian, Ara
Subject: STOP the Grayson Repowering Project

Dear Mr. Krause,

I am writing to express my strong opposition to the Grayson repowering project as outlined in the September 2017 Draft EIR. 999-1

As a resident of Glendale, I do not want my family and especially my children to be exposed to further pollution. You should be concerned that our future and the future of our children is at stake. 999-2

I call on the City to pause the CEQA process and immediately commission an independent study of clean energy alternatives for powering Glendale. This study should be conducted by a group such as NREL or E3 with strong clean energy credentials and not by the consultants who have been working on the Grayson EIR. 999-3

Regards,

Jean-Charles Galiana
Glendale