Workshop on LSE Plans for the 2017-18 IRP Cycle

August 7, 2018

INTRODUCTION

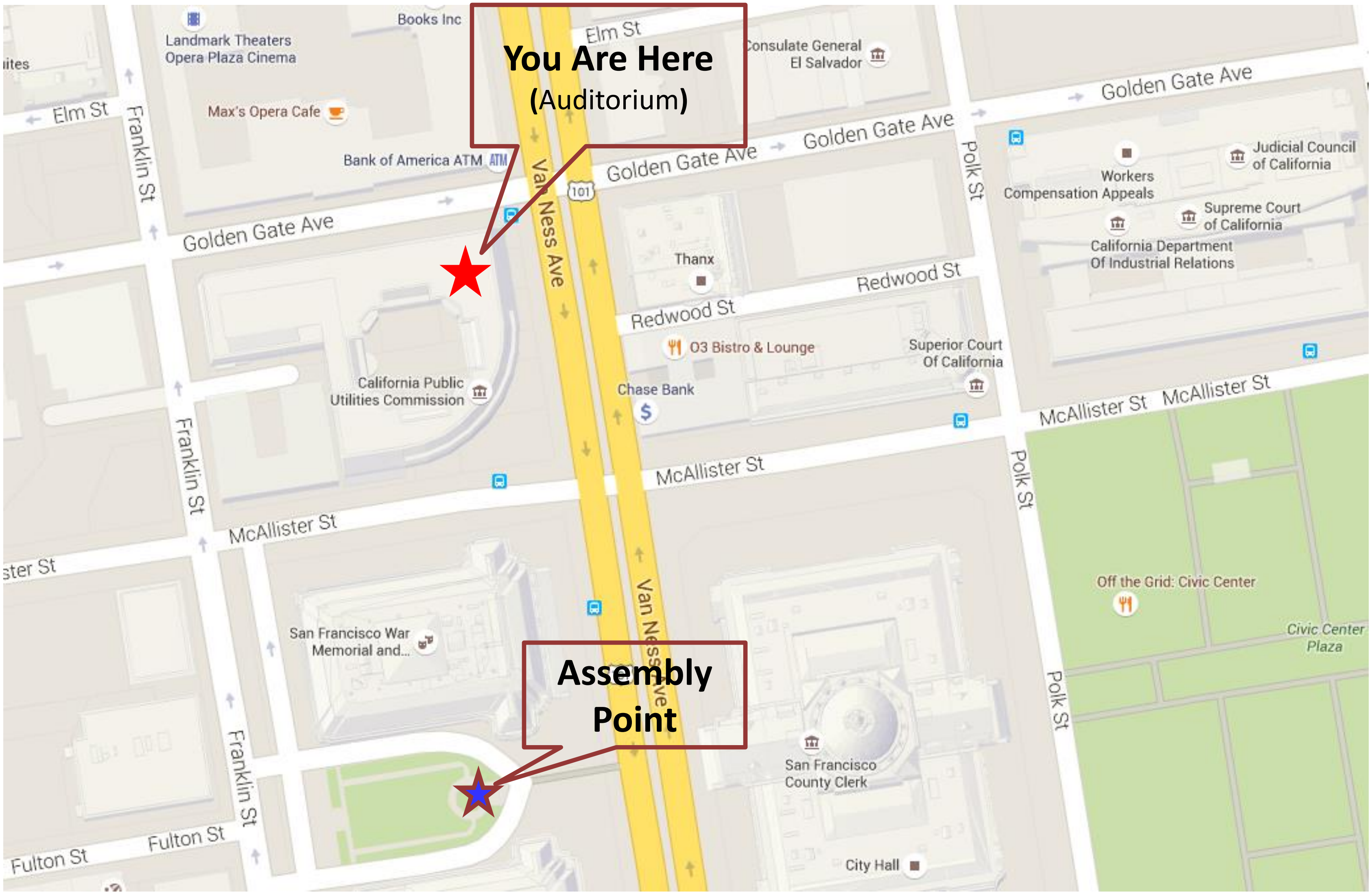
Introduction

- Housekeeping
  - Staff introductions
  - Informal workshop, not on the record
  - Safety information and logistics
- Workshop purpose and agenda
- Background on LSE Plan review process

Safety and Emergency Information

- In the event of an emergency, please proceed out the exits.
- We have four exits: Two in the rear and one on either side of the speakers.
- In the event that we do need to evacuate the building:
  - Our assembly point is the Memorial Court just north of the Opera House.
  - **For the Rear Exits:** Head out through the courtyard and turn right to exit on Golden Gate Avenue. Proceed west to Franklin Street. Continue south on Franklin Street, and continue toward the Memorial Court.
  - **For the Side Exits:** Go out of the exits and you will be on Golden Gate Avenue. Proceed west to Franklin Street. Turn south onto Franklin Street, and continue toward the Memorial Court.

Evacuation Map



Call-in Information

To start or join the online meeting, go to:
https://centurylinkconferencing.webex.com/centurylinkconferencing/j.php?MTID=mc63675f54f27281329fc9ab66ed9c5af [centurylinkconferencing.webex.com]

Meeting number: 717 234 570

Meeting password: !Energy1

Call-in: 1-866-830-2902

Passcode: 2453758#

- Remote callers will be placed in listen-only mode by default. Please submit questions via the WebEx chat to user named ChatMe.
- We will have time for Q&A at the end of each panel.
- Please state your name and organization when asking a question.

Other Information

Wi-Fi Access

- login: guest
- password: cpuc73118

IRP Website

- http://www.cpuc.ca.gov/irp/
- All staff work products are available for download

Restrooms

Out the Auditorium doors and down the far end of the hallway.

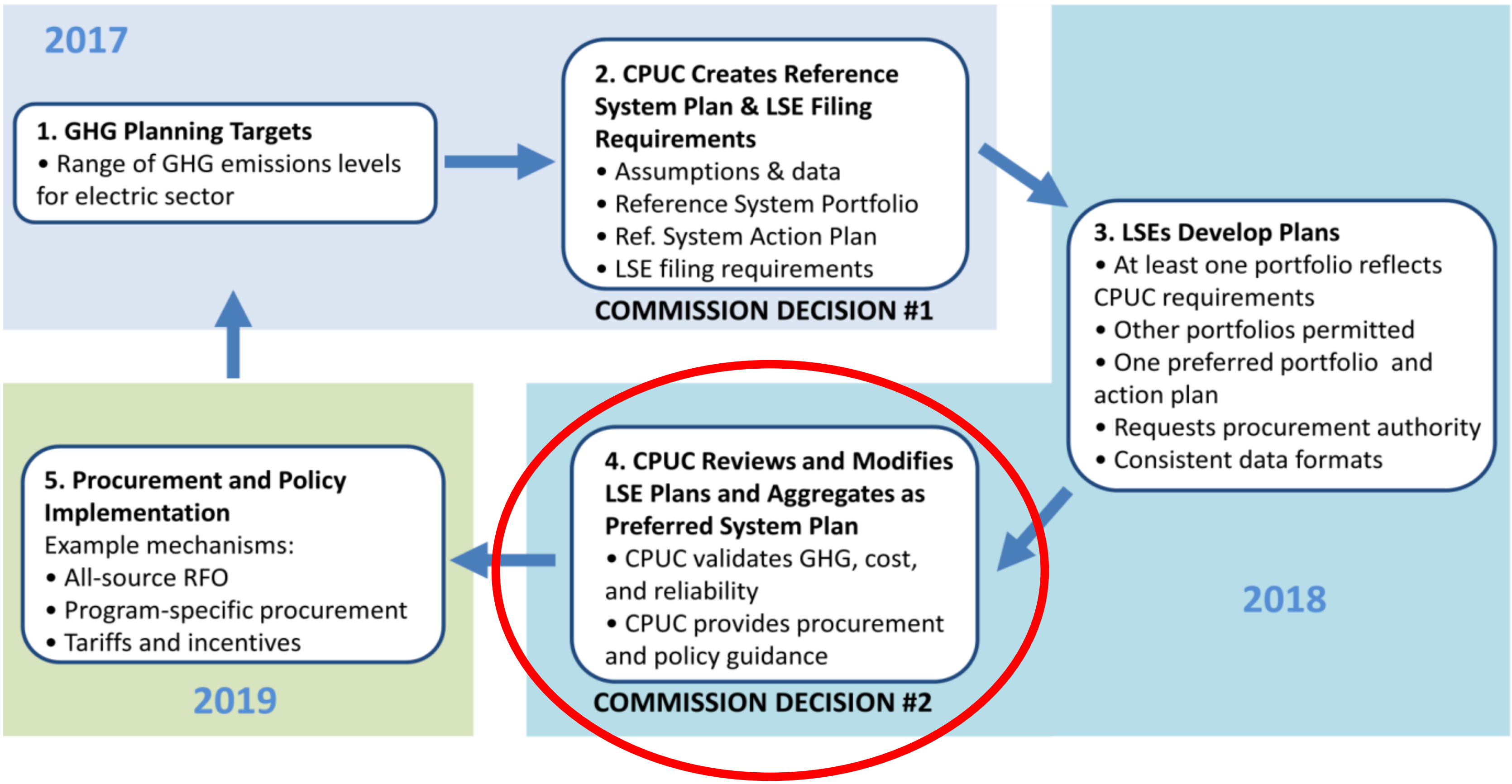
Purpose of Workshop

- Workshop purpose:
  - To provide LSEs an opportunity to present to stakeholders and Commission staff an overview of their IRPs
  - To provide stakeholders with an opportunity to discuss their expectations for the CPUC's review of LSE Plans, development of the Preferred System Portfolio, and outcomes from this first IRP cycle
- Out of scope:
  - Staff's evaluation of individual LSE Plans
  - Recommendations for the 2019 Reference System Plan

Agenda Overview

I.	Introduction	9:30 – 9:40
II.	Community Choice Aggregators' IRPs	9:40 – 11:05
III.	Electric Service Providers' IRPs	11:10 – 12:00
	LUNCH	12:00 – 1:00
IV.	Small and Multi-Jurisdictional Utilities' IRPs	1:00 – 2:00
V.	Investor Owned Utilities' IRPs	2:05 – 3:15
VI.	Non-LSE Stakeholder Panel Discussion	3:15 – 4:15

Entering Step 4 of the IRP Process



- LSE Plans were filed on August 1st; staff has begun the review process

Overview of LSE Plan Review Process and Development of Preferred System Plan

- Staff will review individual LSE Plans for completeness and consistency with Commission direction.
- Staff will aggregate LSE Plans into a single combined portfolio and conduct production cost modeling to ensure reliability requirements and GHG emissions targets are met.
- Commission will approve and/or modify individual LSE Plans and authorize any associated procurement activity, as necessary, to commence in the next 1-3 years.
- Commission will adopt the combined portfolio, the "Preferred System Plan," for use in the CAISO TPP commencing in 2019.

Key IRP Review Process Activities

ACTIVITY	DATE
Staff begins review of LSE Plans and portfolio aggregation process	**Aug. 1, 2018**
Ruling seeking comment on SERVM studies and revised production cost modeling (PCM) guidelines	**Late Aug. 2018**
Stakeholder comments filed and served, including any requests for evidentiary hearings	**Sept. 12, 2018**
Ruling revising PCM guidelines for studying aggregated LSE portfolios; staff to post aggregated LSE portfolio datasets	**Late Sept. 2018**
Ruling and staff proposal issued with proposed Preferred System Plan (PSP) and addressing key issues identified in IRP filings	**Late Nov. 2018***
Proposed Decision on Preferred System Plan	**Early 2019***
Commission Decision on Preferred System Plan	**Early 2019***

* Timing dependent on whether evidentiary hearings are held

Staff Role in Today's Workshop

- Staff is in listening mode
  - We have just begun to review the LSE Plans and have not yet formulated recommendations for the Preferred System Plan
  - We are looking to LSEs and other stakeholders for guidance to consider during the review process
- Questions for discussion today:
  - What elements or themes should staff focus on during its review of LSE Plans and development of the Preferred System Portfolio?
  - How should the CPUC address issues of data confidentiality in sharing the aggregated LSE portfolio datasets with the public?
  - What are the 3-4 most important outcomes that should result from this process?

CALCCA

ADVANCING LOCAL ENERGY CHOICE cal-cca.org

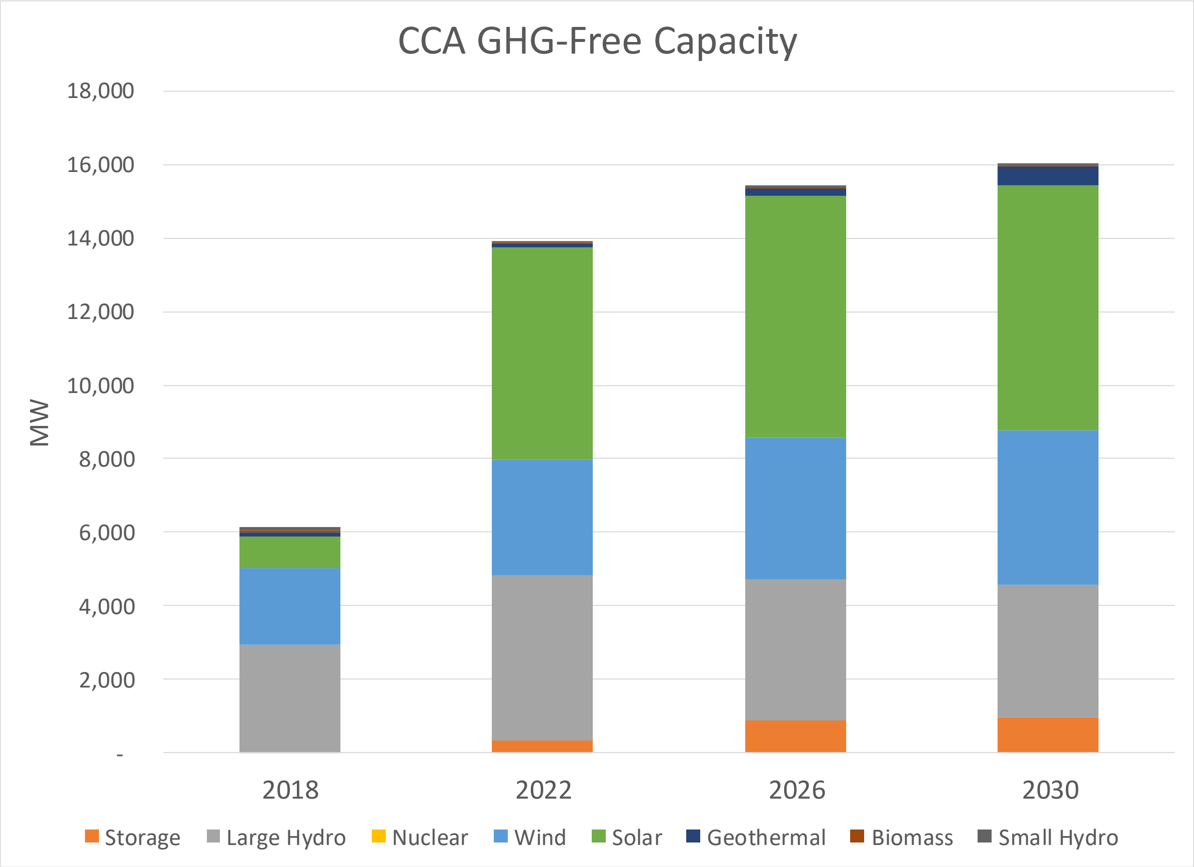
CPUC 2018 Integrated Resource Plan Workshop

August 7, 2018

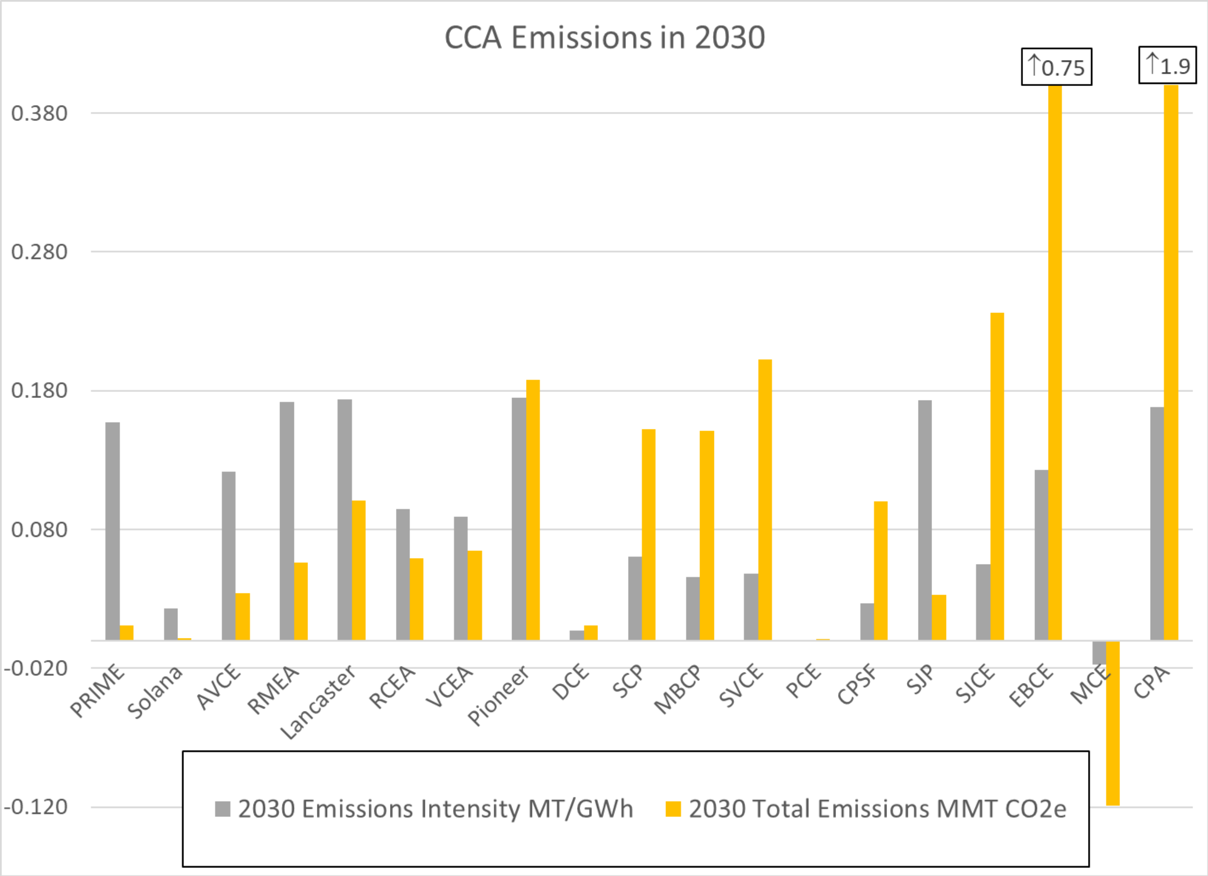
CALIFORNIA COMMUNITY CHOICE ASSOCIATION cal-cca.org

CCA Service in California

Aggregated CCAs GHG-free Capacity



GHG Emissions in 2030



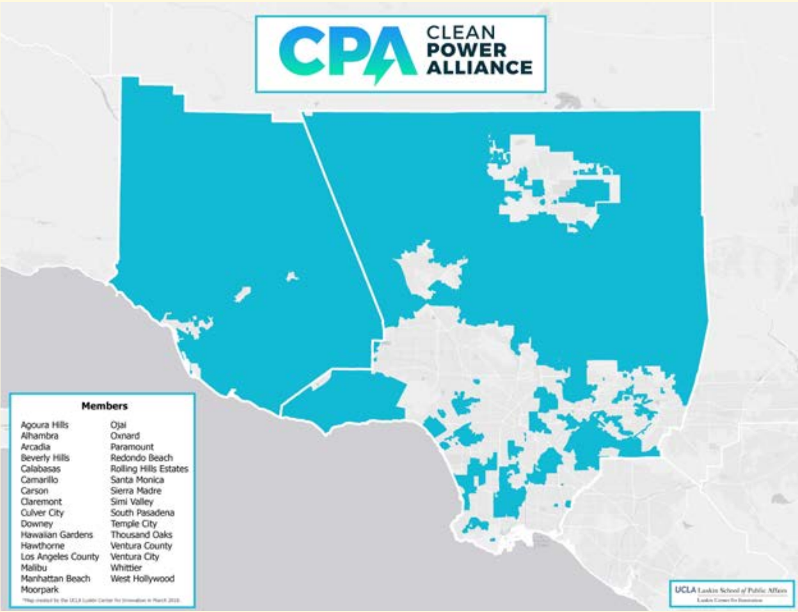
TOPIC 5

CPA 2018 Integrated Resource Plan

August 7th CPUC Workshop

Natasha Keefer, Director of Power Planning & Procurement

Clean Power Alliance Overview



- A Joint Powers Authority, CPA has 31 member jurisdictions within Los Angeles and Ventura counties
- Began offering service to select customers in February 2018 and will complete enrollment of all customers (over 1 million) by May 2019
- Short-term procurement to date; long-term procurement will launch in Fall 2018

CPA Procurement Principles

- Ensure customer affordability
- Ensure CPA’s long-term viability
- Develop portfolio with overall lower GHG emissions than SCE
- Encourage development of cost-effective renewable and distributed energy resources (DERs)
- Discourage use of unbundled renewable energy credits (RECs)
- Promote public health in areas impacted by energy production, including Disadvantaged Communities (DACs)
- Achieve regional economic benefits and workforce development
- Offer customers a choice of differentiated renewable product tiers

CPA Conforming Portfolio

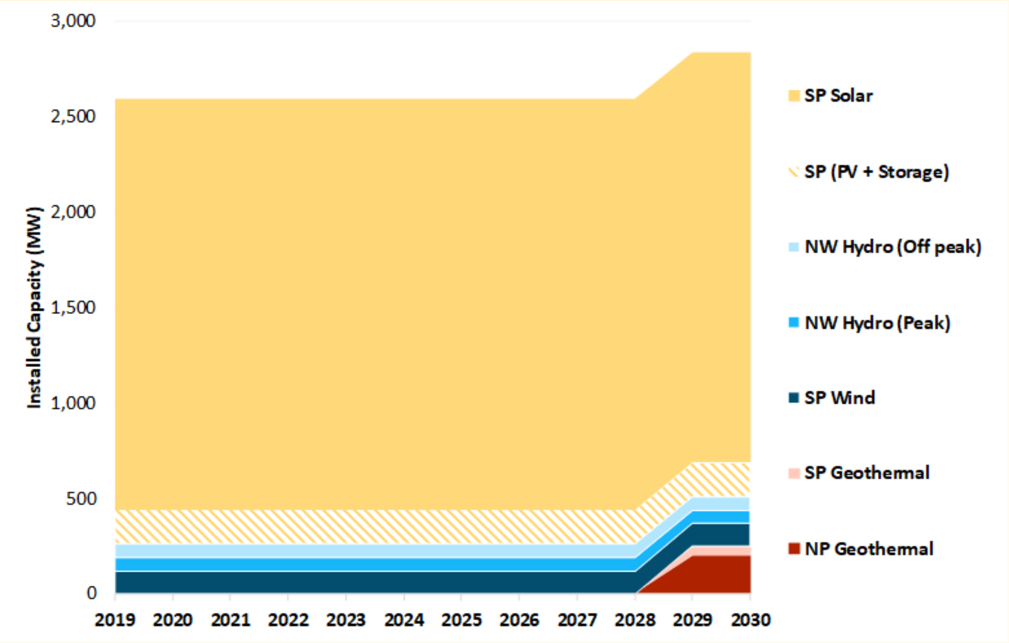
- Assumptions consistent with CPUC system modeling
- Load forecast consistent with 2017 IEPR (mid Baseline mid AAEE mid AAPV):

	2018	2022	2026	2030
Load Forecast (GWh)	1,071	12,009	11,630	11,362

- CPUC emissions benchmark for CPA is 1.992 MMT
- Conforming Portfolio was modeled on a month-hour basis to determine a selection of least-cost power purchase agreements (PPAs)

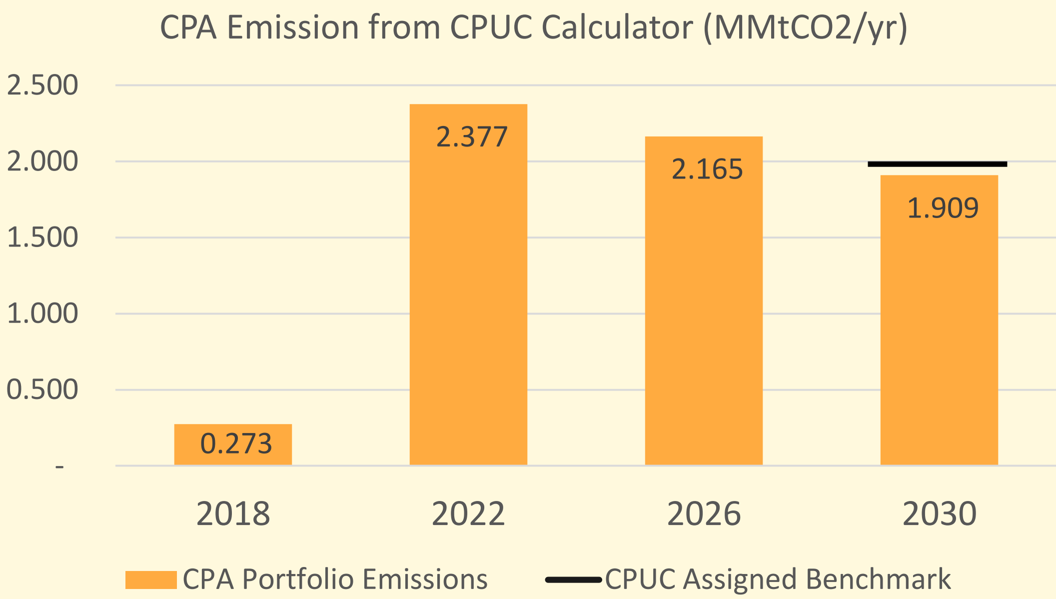
Carbon-Free Resource Mix

- CPA's portfolio is a mix of solar, storage, wind, geothermal, and NW hydro



GHG Emissions

- Conforming Portfolio Emissions are 4% lower than 2030 benchmark



Action Plan

- Launching first solicitation for long-term renewable contracts in Fall 2018
    - Given that CPA has not yet procured long-term resources, the future portfolio may change significantly from this forecast
- Focus on Disadvantaged Communities, both in selection of long-term contracts and deployment of local programs, such as transportation and building electrification
- The Clean Net Short will be a consideration when selecting resources
- Incorporate the following analysis into the next IRP cycle:
    - CPA-specific customer programs and goals
    - Resource mix that incorporates up-to-date, market-based resource costs assumptions

CLEAN
POWER
ALLIANCE

MCE 2018 Integrated Resource Plan

CPUC Workshop (August 7, 2018)

Greg Brehm | Director of Power Resources

Key IRP References - CPUC & MCE

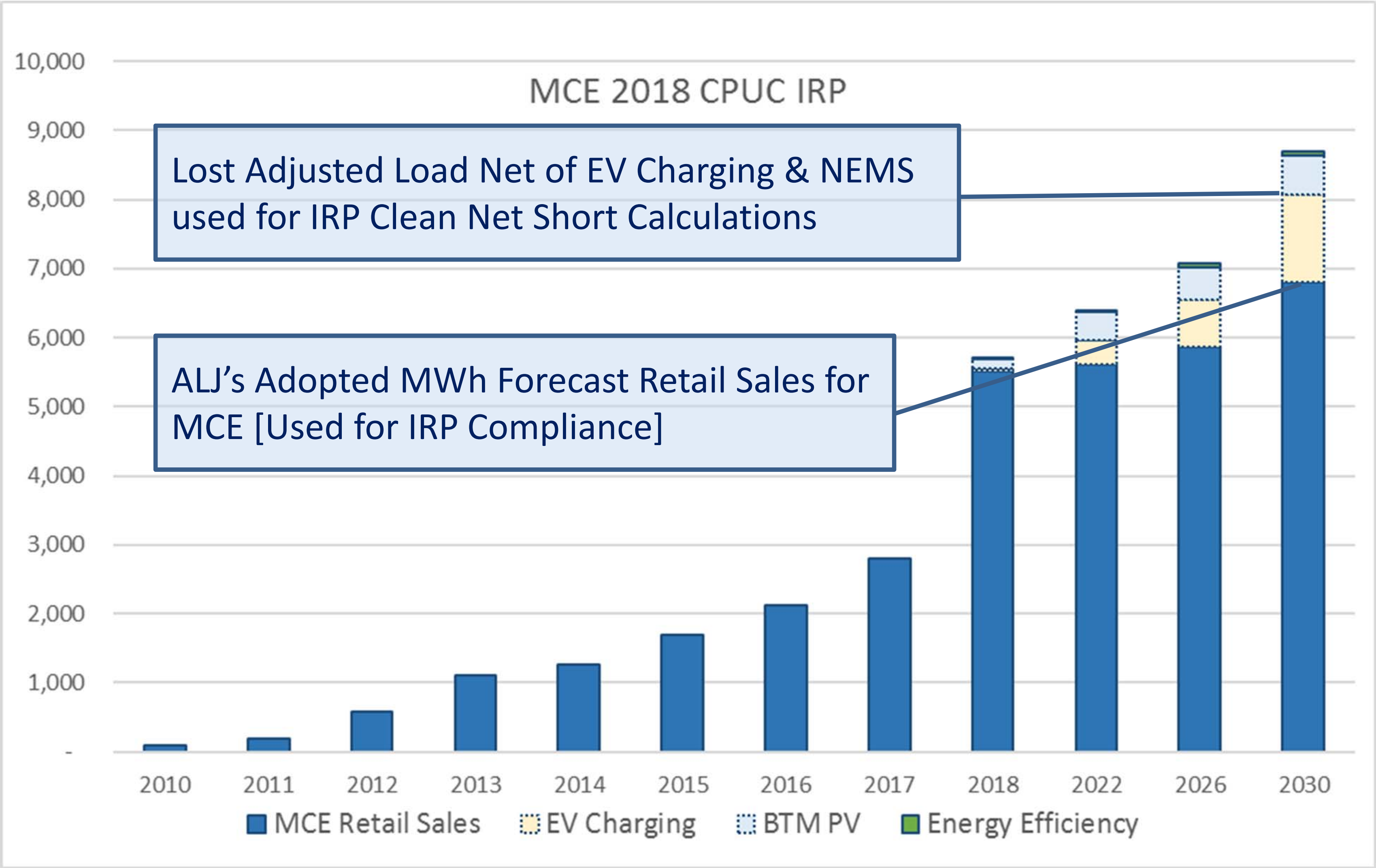
- This California Public Utilities Commission (CPUC) Integrated Resource Plan ("IRP") documents MCE's compliance with ("CPUC") resource planning objectives from 2018 through 2030 based upon MCE's published 2018 IRP.
- MCE's Assigned Load Forecast for IRP (i.e., Managed Retail Sales Forecast)

Retail Load	2018	2022	2026	2030
GWh	5,512	5,618	5,858	6,793

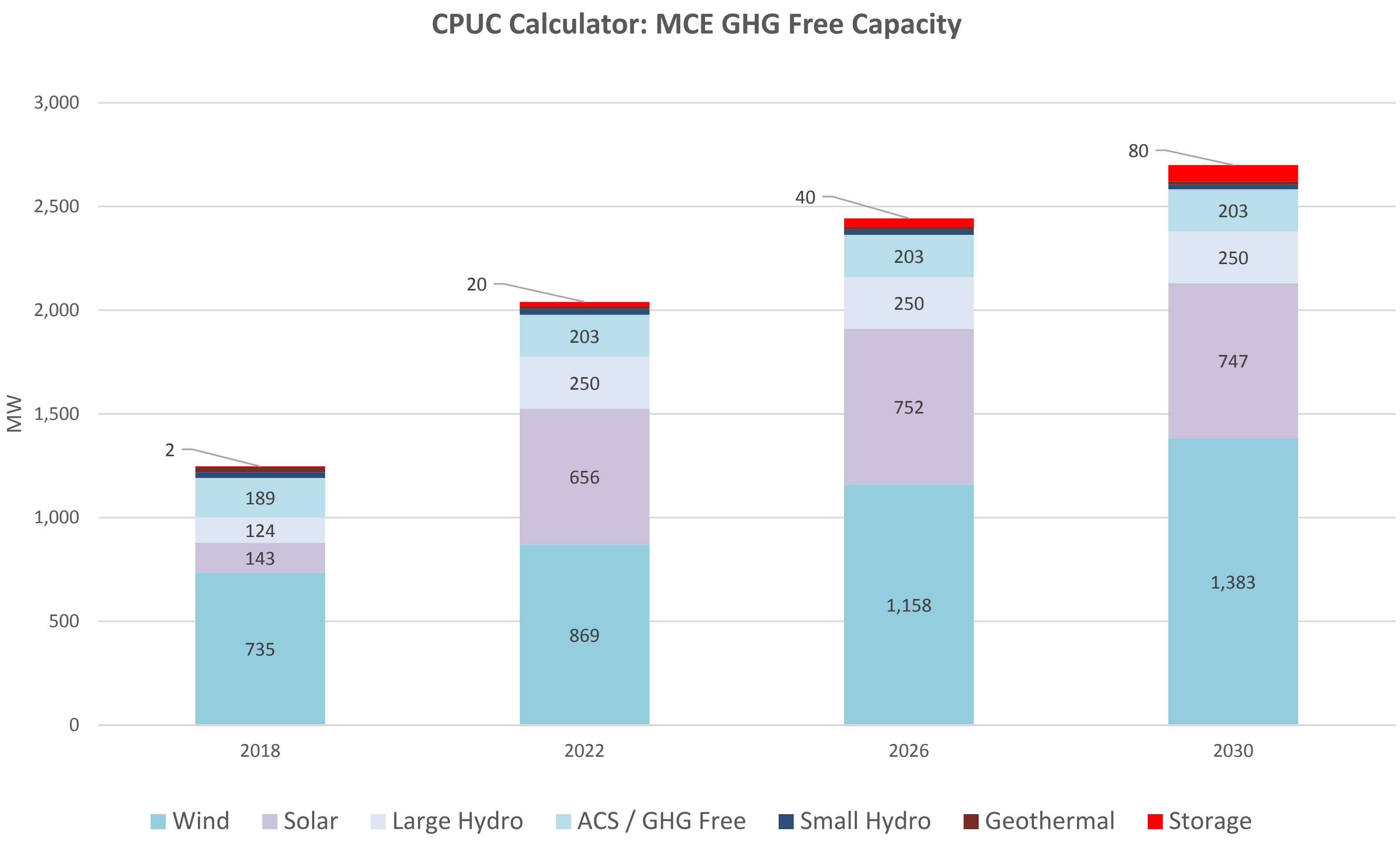
- Differences between Conforming Portfolio and Preferred Portfolio
- MCE uses the LSE-specific 2030 GHG Emissions Benchmark assigned in the ALJ Ruling, 1.207 MMT in 2030
- MCE used the same supply portfolio assumption inputs for both the Conforming and Preferred Portfolios

[1] MCE used its 2019 forecasted hourly load profile based on actual historic meter data (including EEV charging and net of BTM solar) as its baseline reference in the Preferred Portfolio to reflect a full year of customer load with its recent April, 2018 expansion.

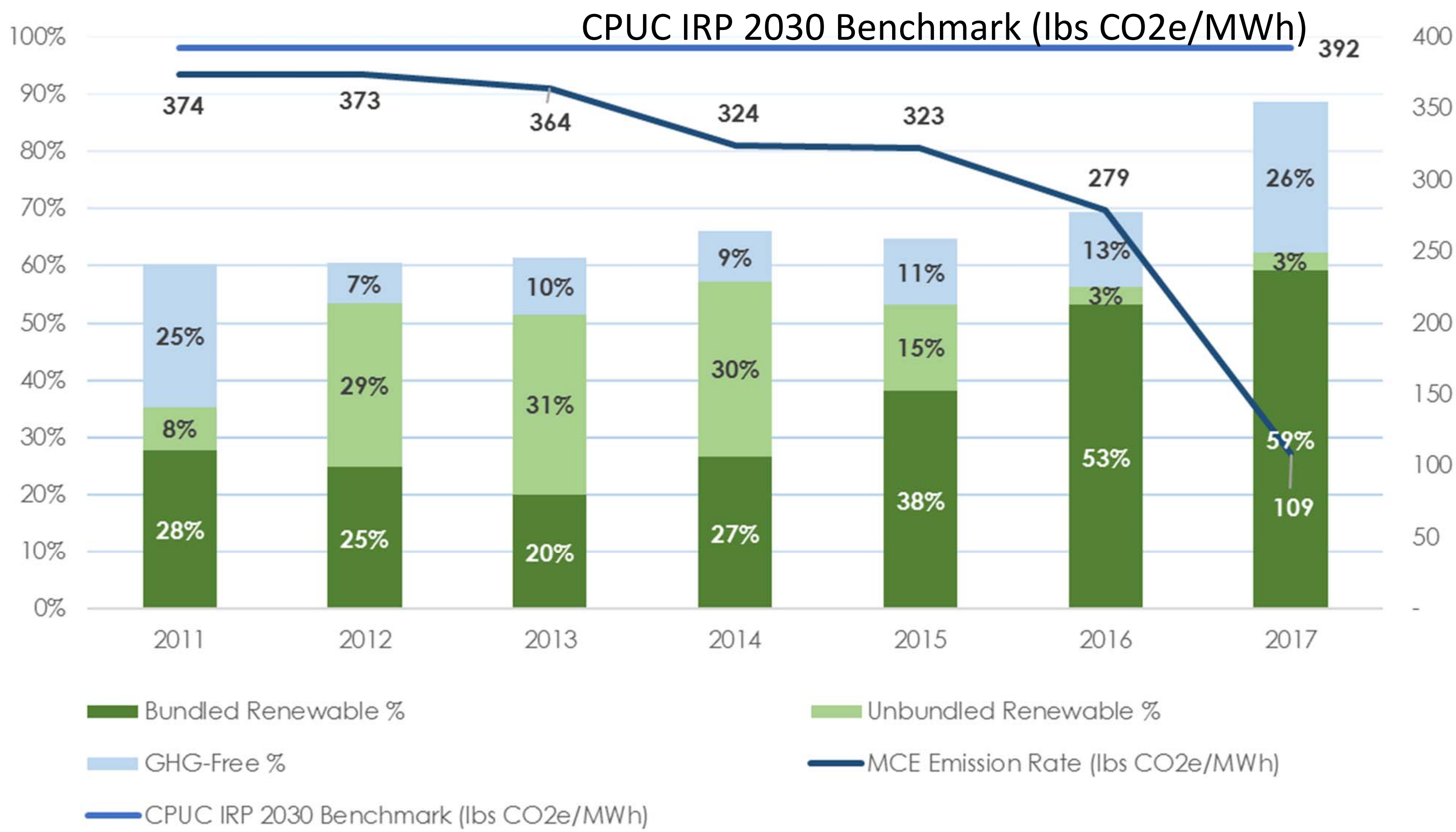
MCE Historical & Forecast Loss Adj. Load



MCE Supply Plan for CPUC GHG Calc.

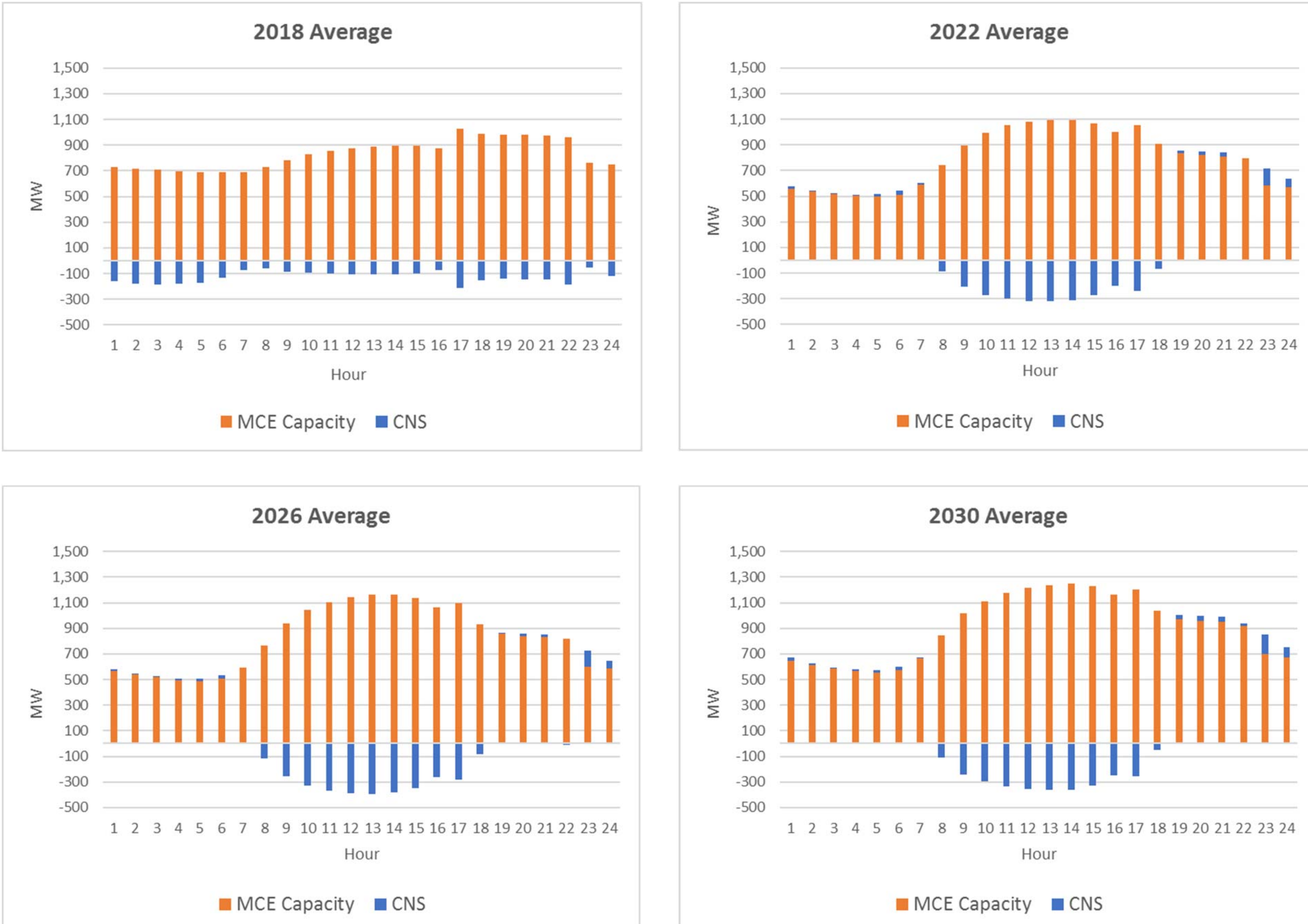


MCE Historical Power Content (2011-2017)



* MCE 2030 Portfolio Emissions Rate ~ 5.67 Lbs/MWh per GHG Calc.

MCE Clean Net Short



MCE's Conforming Portfolio

- The inputs and assumptions as well as hourly load shape used to develop the Reference System Portfolio were used in MCE's Conforming Portfolio.
- The total emissions attributable to MCE's Conforming Portfolio:
  - **0.809 MMT in 2018**
  - **0.190 MMT in 2030**
  - Both are compliant with MCE's assigned benchmark of 1.207 MMT.
  - CPUC IRP resource modeling assumptions:

	2018	2022	2026	2030
Conforming Portfolio Energy for Load (GWh)	6,297	6,642	7,154	8,540
Preferred Portfolio Energy for Load (GWh)	6,169	6,174	6,159	7,083

    - Assumes Base Load scheduling of all GHG emitting resources
    - No opportunity to input Blocked and Shaped supply
    - ACS, Specified Sources, BTM CHP curtailment missing

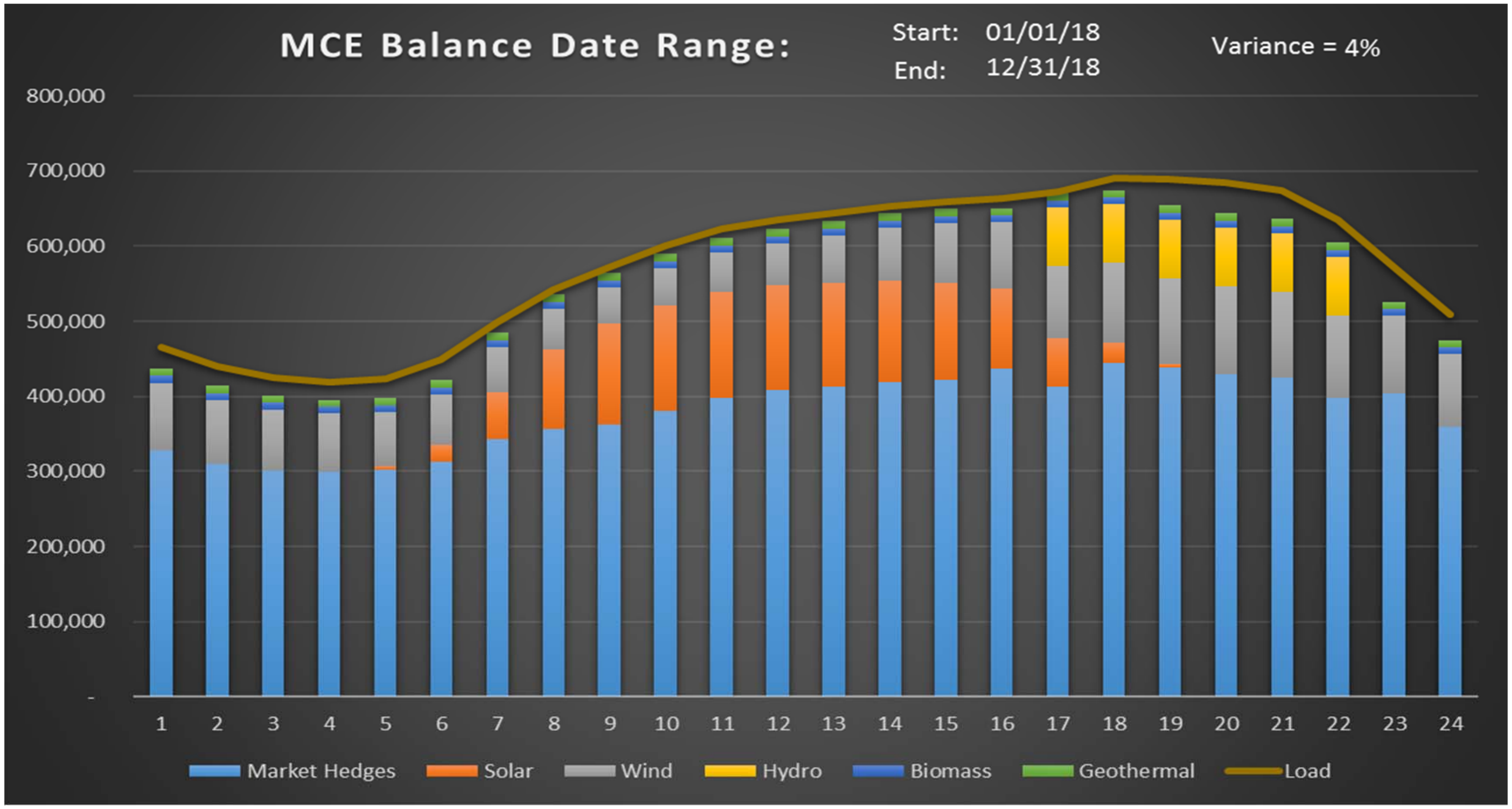
MCE's Preferred Portfolio

- The Preferred Portfolio uses MCE's forecasted load shape based on actual historic meter data.
- The total emissions attributable to MCE's Preferred Portfolio:
  - **0.773 MMT in 2018**
  - **-0.119 MMT in 2030**
  - Both also compliant with MCE's assigned benchmark of 1.207 MMT.
  - MCE's planning process employs MCE-specific set of considerations, including:
    - A forecast of enrolled customers for each MCE program and count by end-use (residential, commercial, etc.)
    - Projections of load modifying impacts such as energy efficiency, behind the meter distributed generation (NEM), and vehicle electrification are added to MCE's baseline electricity and capacity forecast
    - Net open positions for energy & capacity on various time scales including calendar year, month, hourly and sub-hourly
    - Portfolio selection is based on GHG reduction, load hedge effectiveness, relative cost, geographic diversity, resource adequacy deliverability and value, and technology diversity, among other considerations

MCE's Planning & Procurement Process

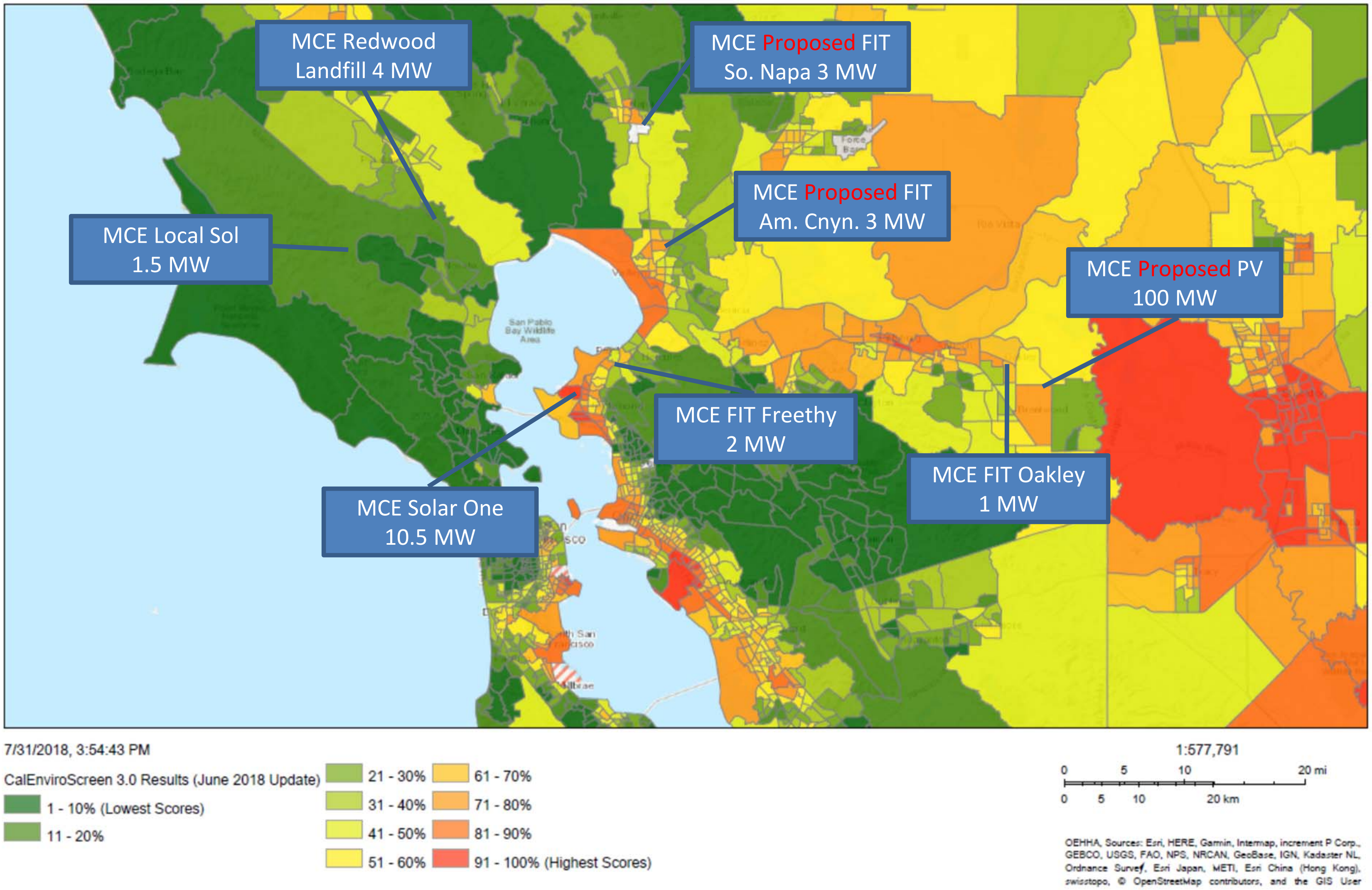
MCE's resource planning process focuses on:

- GHG reduction by scheduling RPS and GHG Free Clean-energy purchases/sales to meet IRP targets, matched against hourly expected load(including planning reserves and losses).
- Because of April 2018 expansion, MCE relied on higher volumes of System Hedges to provide rate certainty in 2018



CalEnviroScreen 3.0

CalEnviroScreen 3.0 Results (June 2018 Update)



Policy & Planning Considerations

- MCE's currently effective IRP establishes the following clean energy goals:

	2018	2019	2020	2021	2022	2023	2024	2025
Renewable	57%	60%	63%	67%	70%	73%	77%	80%
GHG-Free	78%	81%	84%	87%	90%	94%	97%	100%

- MCE has surpassed its specified clean-energy targets in recent years due to strategic purchases of cost-effective GHG-free and renewable energy supply (replacing conventional power source price hedges)
- AB 1110 implementation may necessitate different product purchases
  - Uncertainty regarding Bucket 2 GHG emissions
  - Bucket 3 environmental attributes removed
- MCE may amend its clean-energy targets reflected in MCE's IRP in consideration of a changing energy landscape within Northern California

Questions

POWERED BY MCE
LIGHT GREEN
50%
RENEWABLE

POWERED BY MCE
DEEP GREEN
100%
RENEWABLE

WE'VE GOT MCE
LOCAL SOL
100%
SOLAR POWER

Greg Brehm
Director of Power Resources, MCE
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MCE Clean Energy
My community. My choice.

Redwood Coast Energy Authority

2018 Integrated Resource Plan

Alternative Conforming Portfolio

Allison Campbell

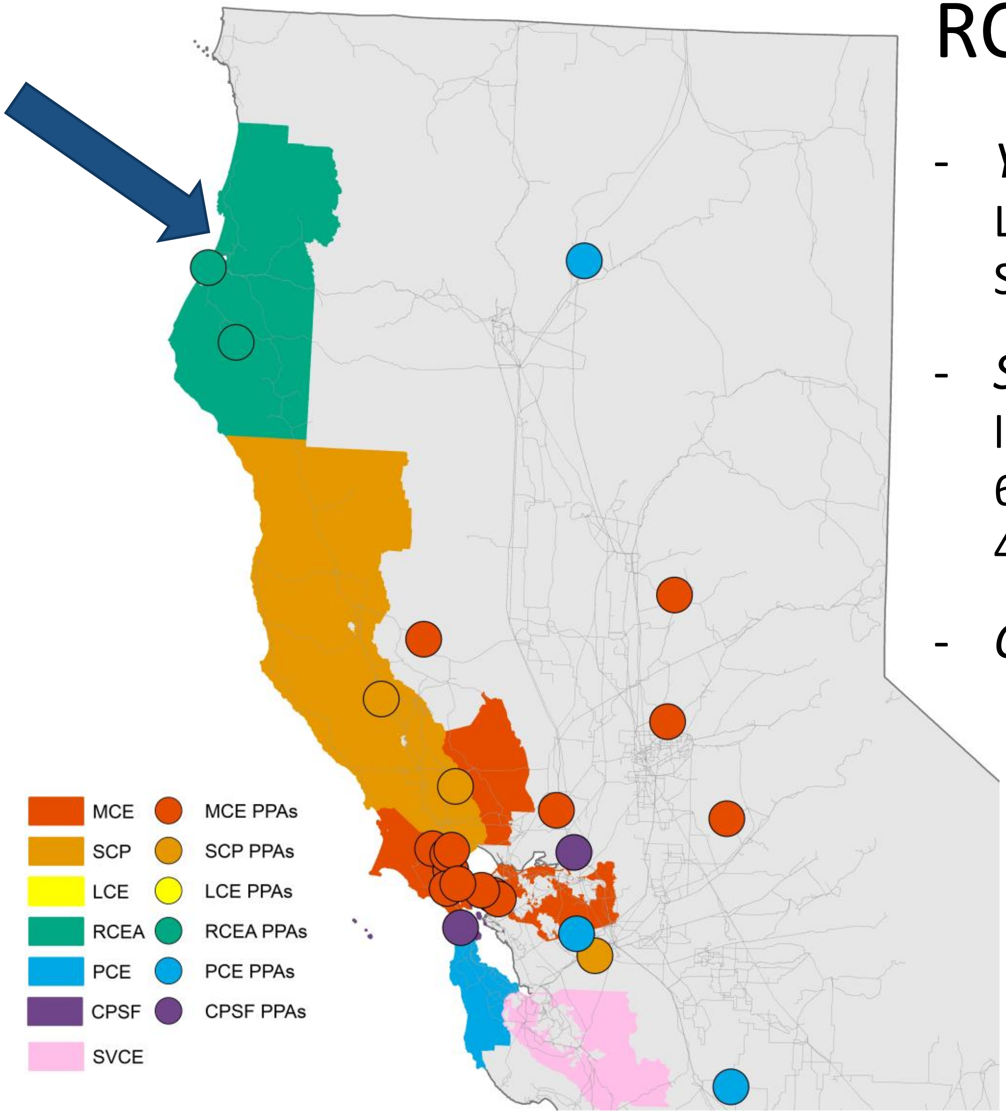
Manager of Power Resources

CPUC Workshop 8/7/18

REDWOOD COAST EnergyAuthority

Who is RCEA?

Community Choice Energy Program



RCEA is...

- *Young:*
  Launched May 2017
  Starting long-term contracts
- *Small:*
  less than 700 GWh retail load
  62,000 accounts
  4 CCE staff members
- *Committed to local investment in power:*
  - Existing Steel in Ground
  - New Power – In Humboldt County

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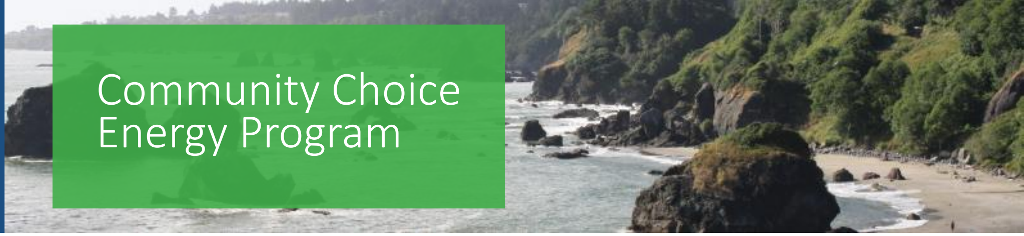
Source: UCLA Luskin Center http://innovation.luskin.ucla.edu/content/growth-community-choice-aggregation-impacts-californias-grid

RCEA Program Launch Guidelines



Maximize the use of local renewable energy while providing competitive rates to customers.

Procurement Targets	
Existing Local Biomass	20 MW
Existing Local Small Hydro	2 MW
New Local Solar FiT	6 MW
New Utility Scale Solar	15 MW
New Battery Storage	2 MW
New On-shore Wind	Up to 50 MW
New Off-shore Wind	tbd
GHG-Free	*80%*

Programs & Energy Efficiency
Public Agency Solar Assistance
Fuel Switching
Electric Vehicle Charging Infrastructure

Program Launch Guidelines adopted by RCEA board September 2016 for 2017-2022

REDWOOD COAST EnergyAuthority

Alternative Plan

Maximize the use of local renewable energy while providing competitive rates to customers.

1. Existing Biomass contracts (sunset 2022)

2. Small hydroelectric – 2 MW 2022 through 2030

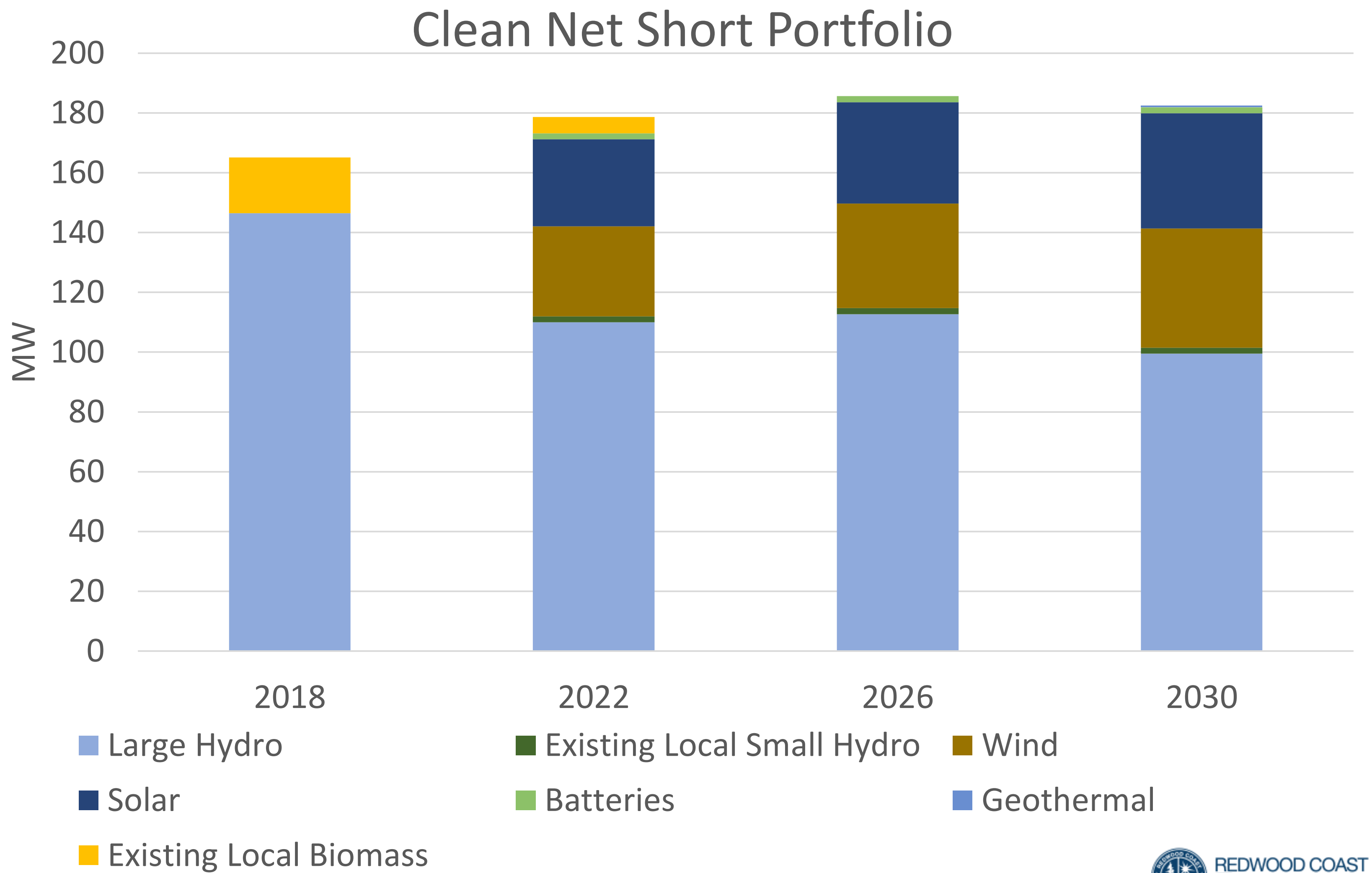
3. 80% GHG-free power

4. Battery storage – 2 MW 2022 through 2030

5. Additional PCC 1 to meet minimum RPS compliance
   (solar, wind, and geothermal)

Conforming Portfolio

Community Choice
Energy Program



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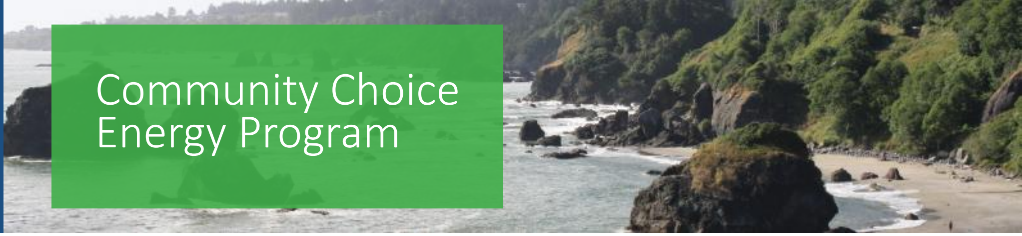
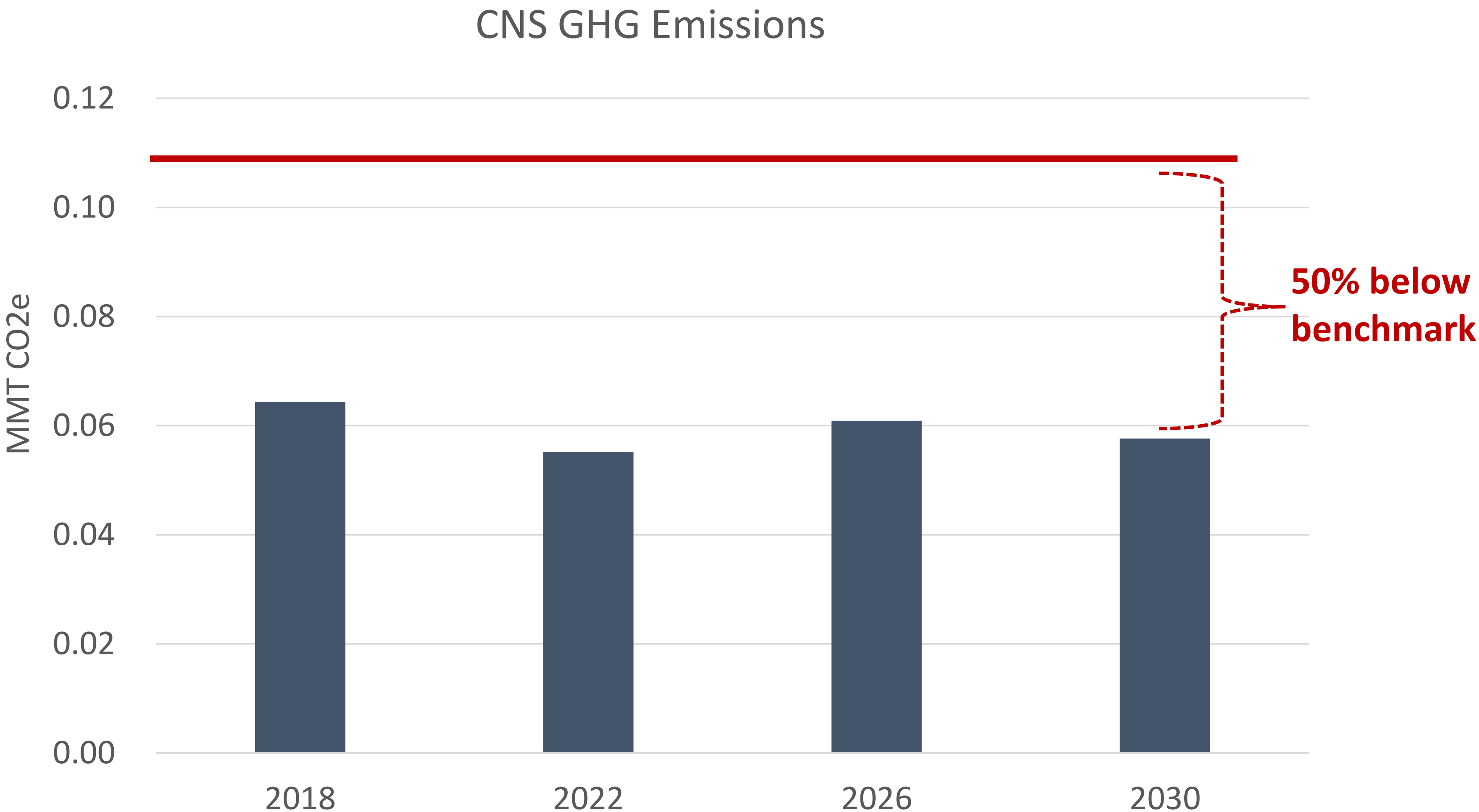
GHG Emissions Below Benchmark



Community Choice Energy Program



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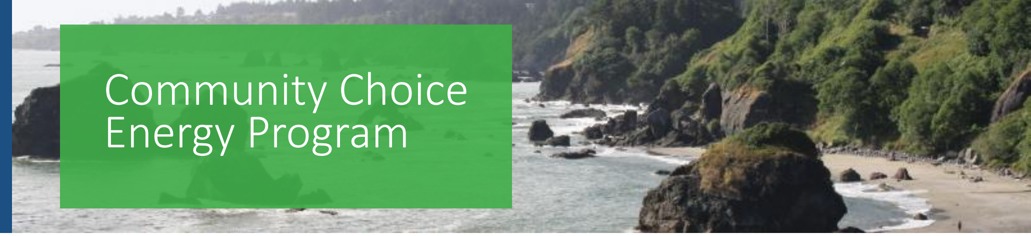
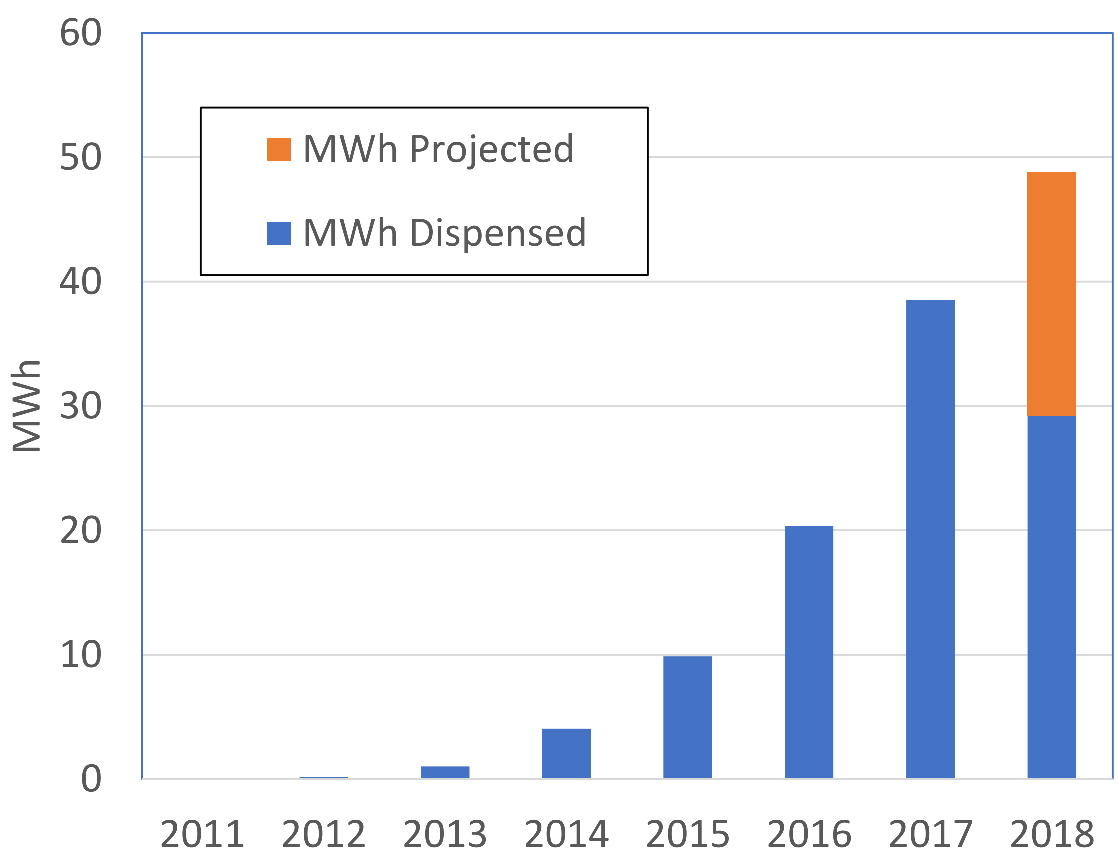
Transportation Electrification



#	City	Address	Notes
1	Trinidad	400 Janis Court, CA	In the very front of lot
2	McKinleyville	1514 Central Ave, CA	Around the back by totem pole
3	Arcata	1459 8th St, CA	At the main entrance
4	Arcata	685 F St, CA	8th & Fst Prking Lot by dumpster
5	Blue Lake	777 Casino Way, CA	In front of Tribal Govt office
6	Blue Lake	111 Greenwood Rd, CA	In middle of lot at city hall
7	Willow Creek	38949 CA 299, CA	Front of main lot by museum
8	Eureka	718 3rd St, CA	Front parking spot in lot
9	Eureka	4 C St, CA	In front of Jack's in lot
10	Eureka	707 L St, CA	Around the back of lot near 7th st
11	Eureka	2700 Dolbeer St, CA	Opposite of main entrance in lot
12	Fortuna	638 11th St, CA	On 11th Street opposite Cty Hall
13	Ferndale	361 Main St, CA	Middle of parking lot
14	Rio Dell	203 Wildwood Ave, CA	In lot next to Pizza Factory

Plug-in Electric Vehicle Electricity Growth



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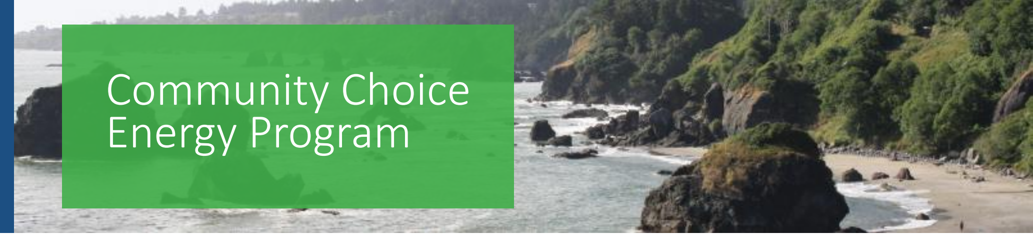
Lessons Learned



1. CO_2e emissions are best framed in **total mass** <u>and</u> **emissions intensity:** Transportation electrification will contribute to RCEA load growth

2. 2022-2030 portfolios will change dramatically: Young CCAs still establishing long term contracts

3. Clean Net Short Hourly Load Balance: We will use the Hourly Load Balance when considering adding to our portfolio


Thank you
REDWOOD COAST
EnergyAuthority

2018 Integrated Resource Plan

CPUC Workshop (August 7, 2018)

CB Hall, Compliance Analyst

Sonoma Clean Power

SCP Overview

- Joint Powers Authority governed by an 11-member Board of Directors
- Launched in May 2014
- Serves most of Sonoma and Mendocino counties: 223,000 accounts
- 2017 Retail Load: 2,367 GWh
- 2017 Peak Load: 580 MW (Sep 1st @4pm)
- 22 employees, based in Santa Rosa
- Key mission: GHG reductions through clean power, with a strong focus on electrification of transportation and buildings

SCP's Retail Load Forecast

CEC's Adopted 2017 IEPR Forecast for SCP
[Mid Baseline mid AAEE mid AAPV version of Form 1.1c Published by the CEC on February 16, 2018]

Unit	2018	2022	2026	2030
Retail Sales (GWh)	2,665	2,598	2,550	2,507

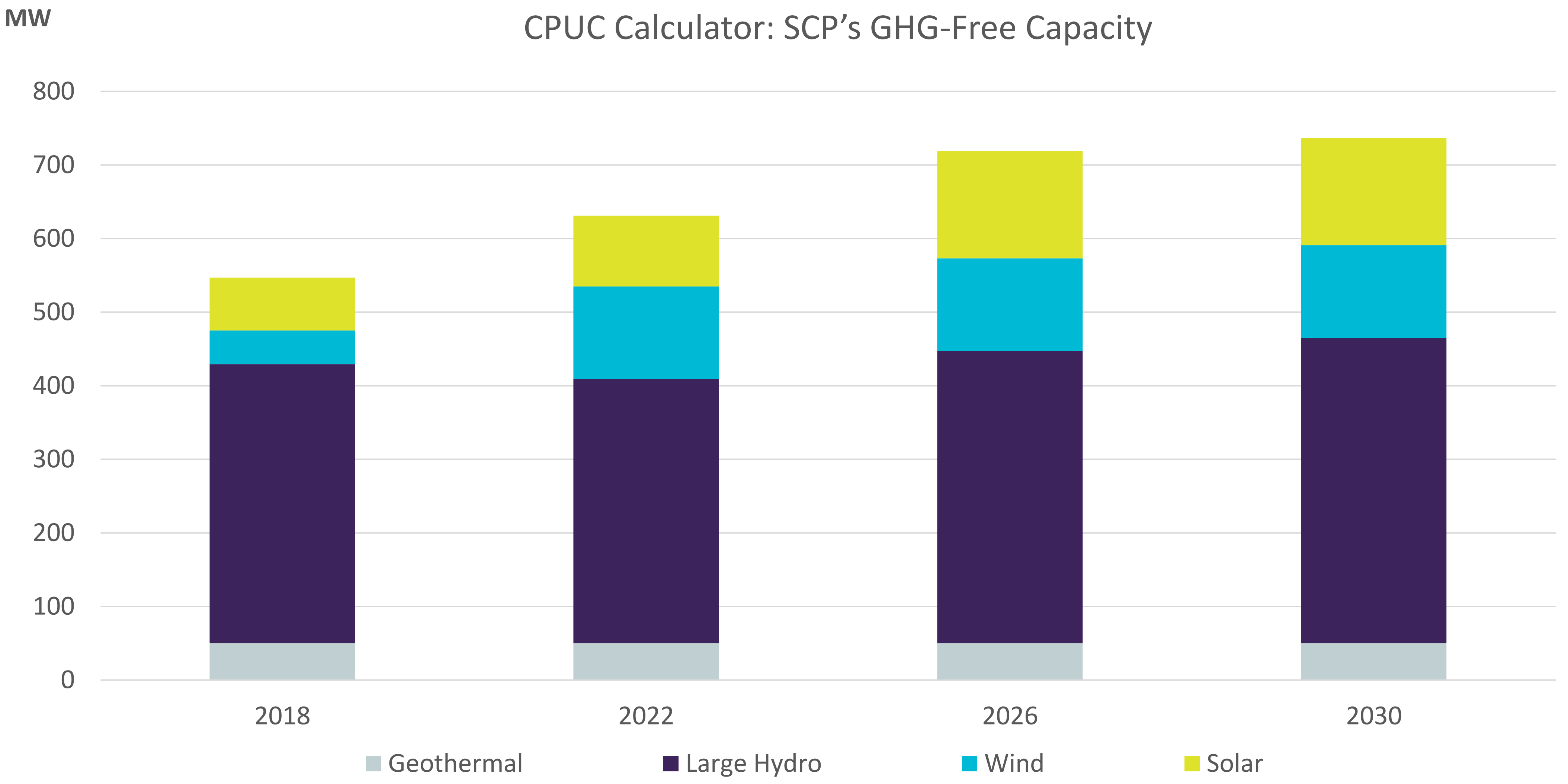
SCP's Internal Forecast
[As of July 2018. This forecast is continually changing]

Unit	2018	2022	2026	2030
Retail Sales (GWh)	2,544	2,548	2,543	2,545

SCP's Key Assumptions

- Population growth
- Housing stock and fire rebuild efforts
- EV growth and other electrification
- BTM Solar
- Energy Efficiency
- SCP opt-out Rate

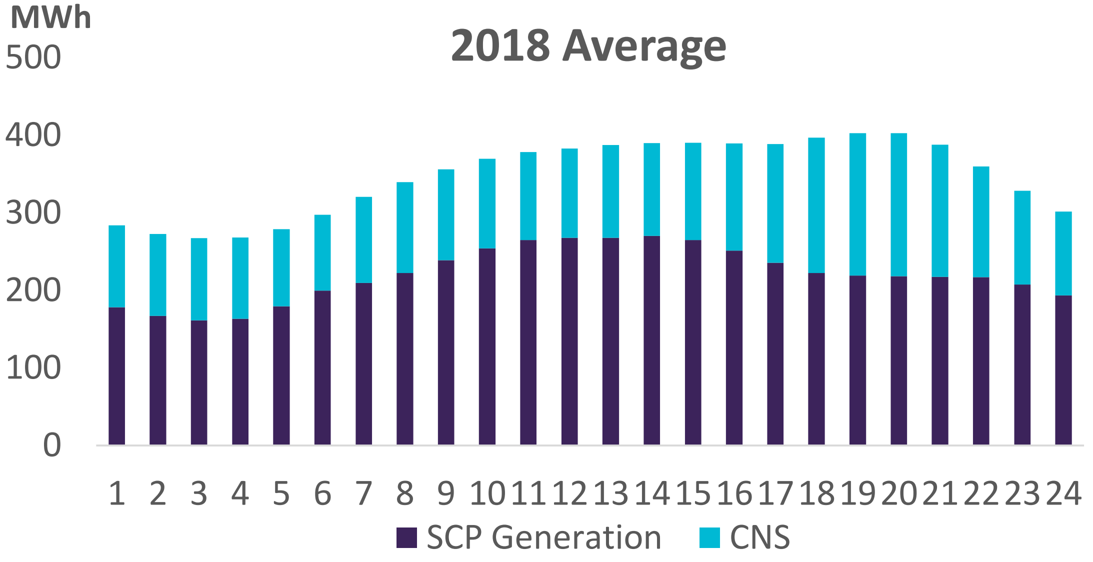
SCP Marrying Geothermal & Hydro with Wind & Solar

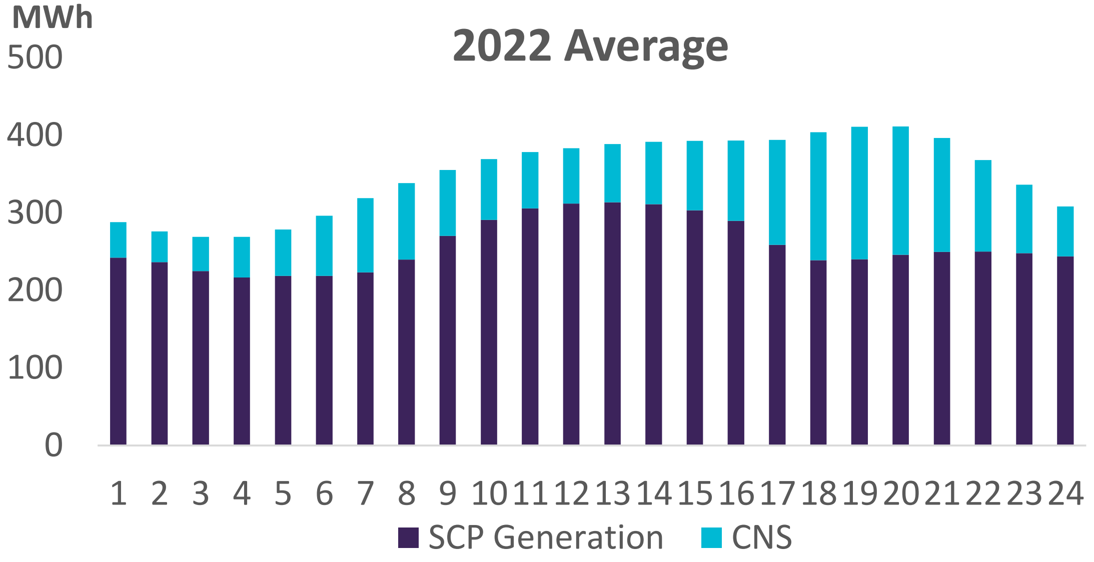


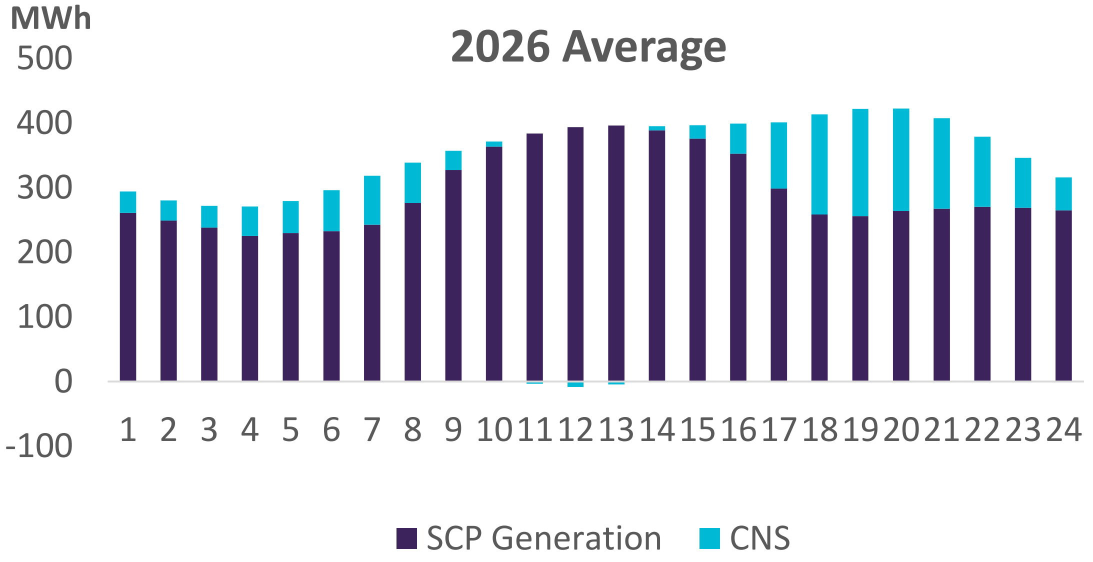
***Note**: Excludes contracts for PCC 2*

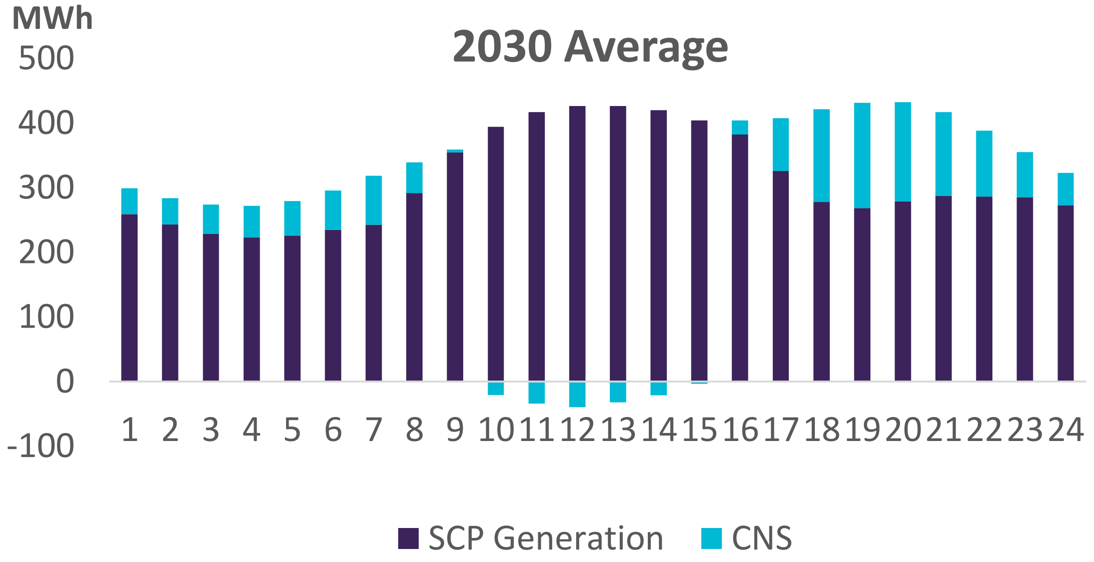
SCP’s Clean Net Short

Based on CPUC Calculator

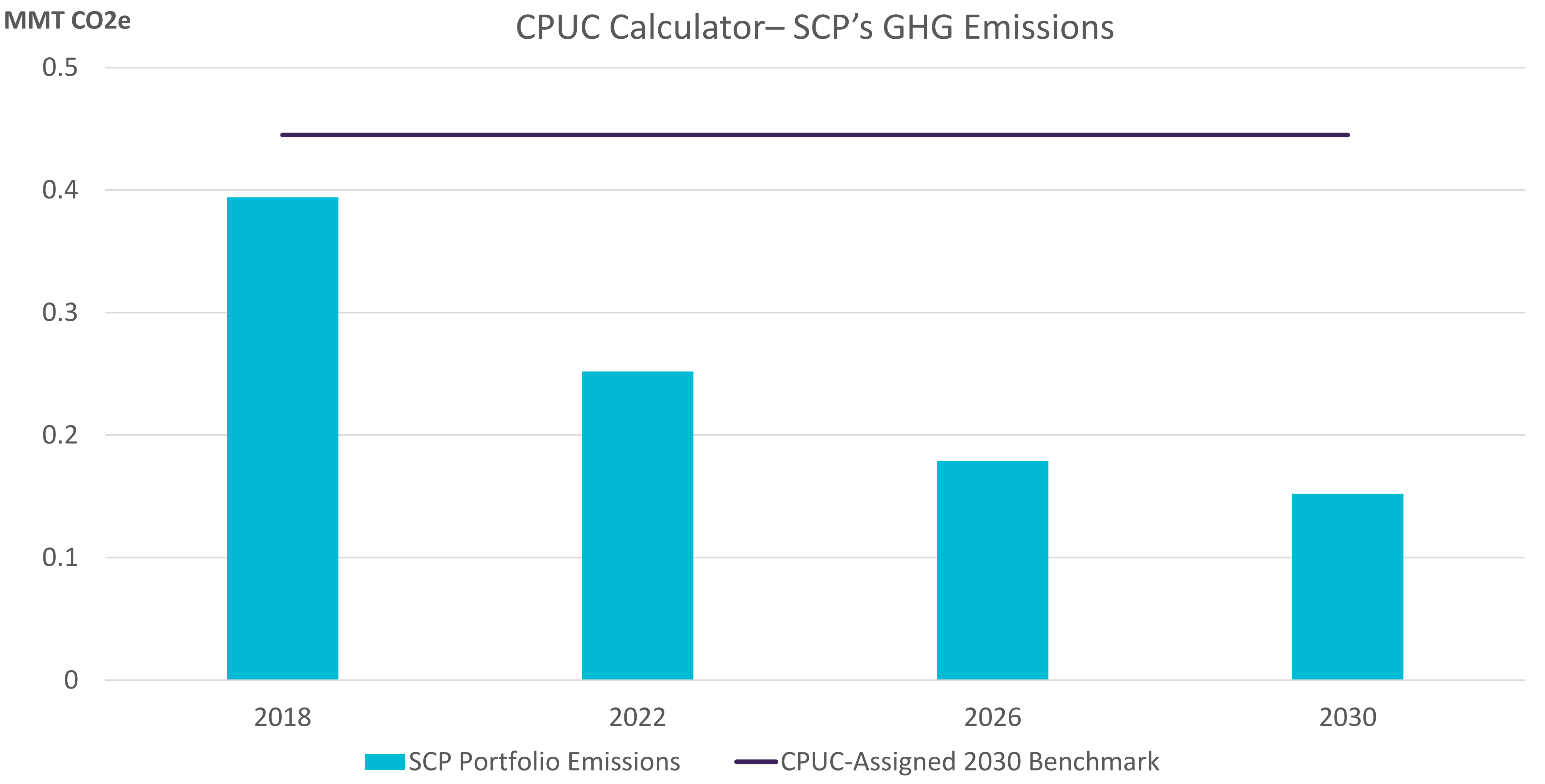








SCP Emissions Already Below 2030 Benchmark



***Note**: Excludes contracts for PCC 2, and also based on CPUC's hourly methodology*

SCP Working to Electrify Transportation and Buildings

Transportation-Related

Discounted EVs and Chargers

Building-Related

Advanced Energy Rebuild, Induction Cooking, Heat Pumps and Energy Market Place

SCP is on track to reach its own ambitious greenhouse gas (GHG) emissions **intensity** target of 75 lbs CO2e/MWh (0.034 MT CO2e/MWh) by 2030

Thank you

Sonoma
Clean Power

Direct Energy Business

2018 California Integrated Resource Plan

7 August 2018

Direct Energy Introduction

BROAD RETAIL PROVIDER OF ENERGY SERVICES

- Retail and wholesale provider of power, gas, RA, and environmental commodities

- 4 million customer relationships, multiple brands and approximately 5,200 employees

- Growing presence in BTM solutions and innovative technologies

Long and growing presence in California

IRP Development

Approach and Methodology

APPROACH AND METHODOLOGY

- Load Forecast
  - Current basis consistent with IEPR filing
  - Extend through 2030, taking into account BTM impacts
- Renewables
  - Assume contracts extended through 2030
  - Calculate net short based on RPS compliance and customer demand
- GHG
  - System power to fill needs not met by renewables
  - Modified GHG Calculator inputs for Preferred Portfolio
- RA
  - As with RPS, extend current resources
  - Integrate future battery procurement

IRP Development

Results and Next Steps

RESULTS

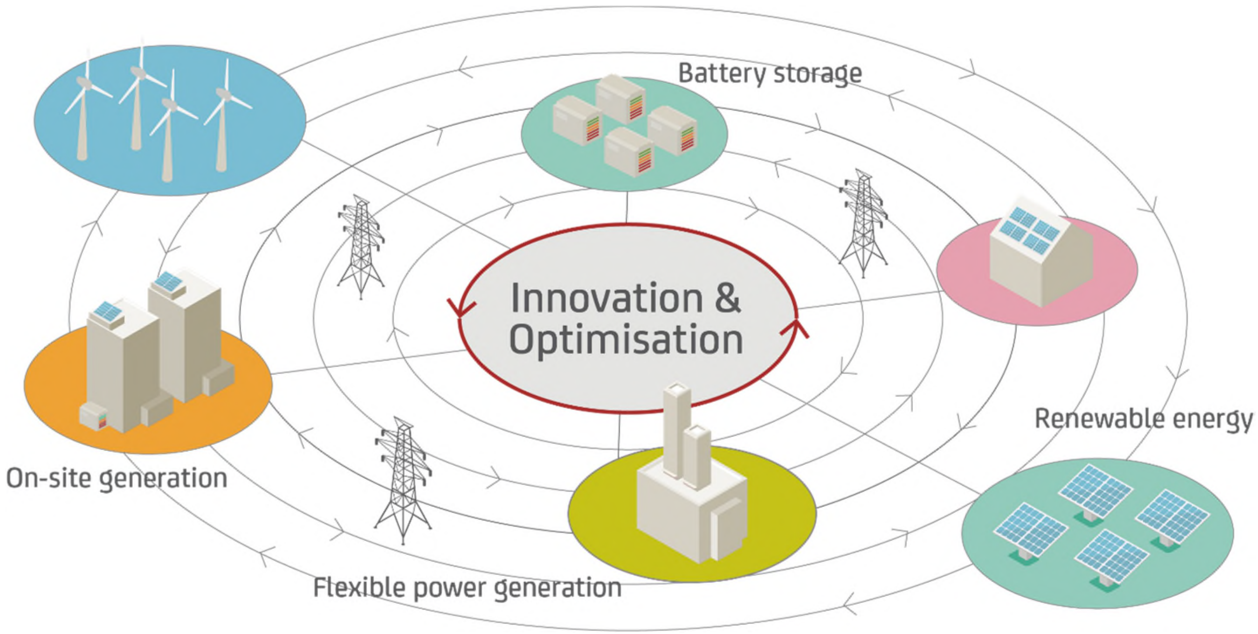
- Forecasting ~100 MW of **new renewable** procurement

Type/Location	Energy (GWh)	Notes
Tehachapi Solar	40	New build
Central Valley North Solar	51	New build
SoCal Desert Solar	105	New build
Imperial Solar	50	New build
Pacific NW Wind	33	New build, PCC2
Geothermal	16	Existing resources, PCC2

- Preferred Portfolio **GHG profile well within CARB range**, nearly identical to CPUC target. Likely to be below based on CARB compliance rules.
- **Limited need for new RA capacity** beyond preferred resources. Flex and local needs rising, but offset by changes to load and customer behavior.
- **Portfolio total emissions falls by just over 50 percent** 2018 to 2030; DEB does not own or operate any emitting facilities in DACs. Newest long-term RPS eligible contract within a DAC.

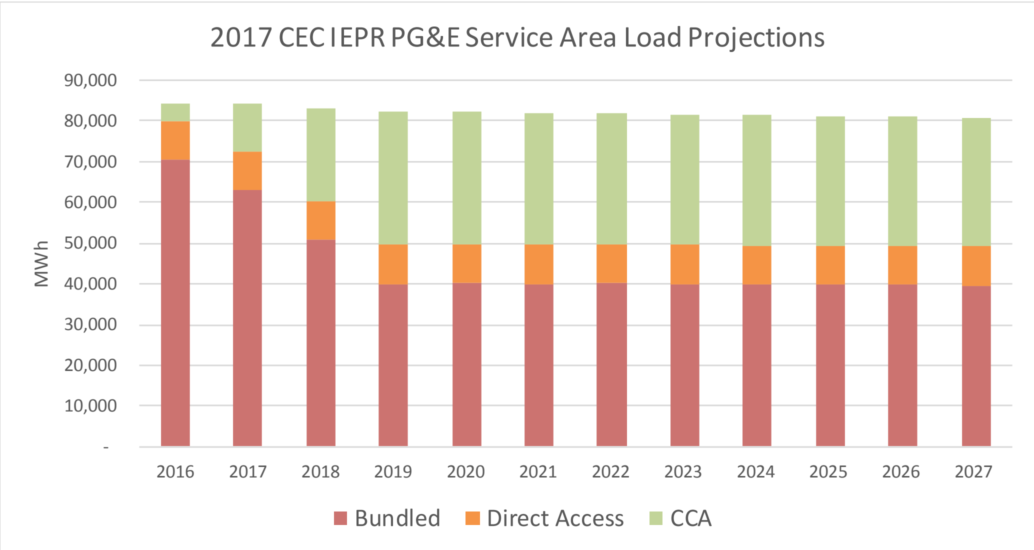
ACTION PLAN

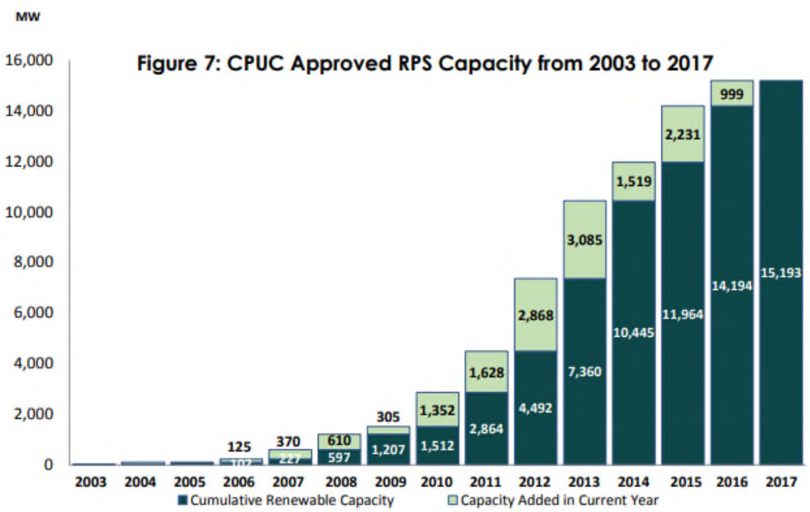
- New RPS and Longer-Term RA Procurement
- Extensive and enhanced BTM resources
- Regular review of contracting for environmental and DAC goals
- Meet needs of changes in consumer choice



BARRIER ANALYSIS

- Changes in Load
- Procurement Regulatory Requirements
- RA Program Modifications and Resource Availability

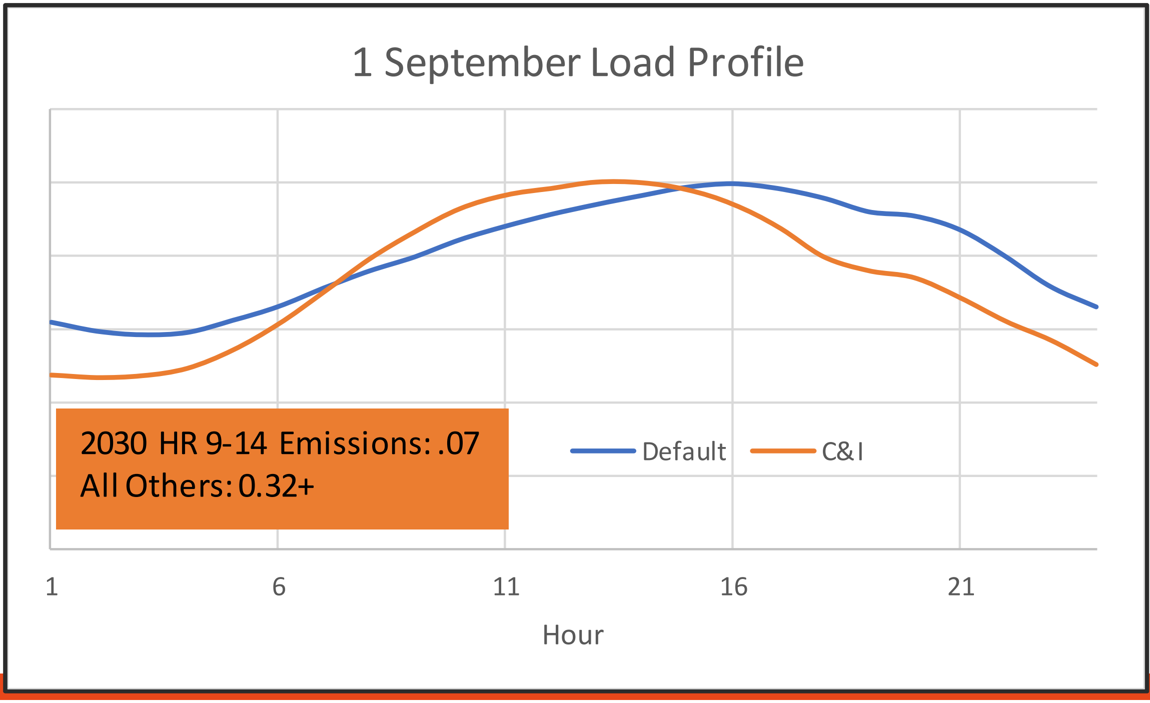




Data source: IOU Project Update Submissions to the CPUC's RPS Contract Database (October 2017)

FUTURE IRP IMPROVEMENTS

- Credit for NBCs to LSEs
- Reflect C&I specific inputs: Load, consumer behavior, losses
- Calculators for NOx and PM emissions
- Align IRP with statewide compliance goals and filings
- Continued strong collaboration with CPUC staff



Scott Olson

Director, Western Government & Regulatory Affairs

Scott.Olson@directenergy.com

Just Energy Solutions Inc.
2018 Integrated Resource Plan

Investment and action from the demand side of the grid will deliver the future faster

just energy™

ENERGY MADE EASY

About Just Energy

20 years of energy experience

- Products help customers
  - manage price and volume risk for natural gas and electricity
  - reduce energy consumption through efficiency measures
  - support the transition to a low-carbon energy system

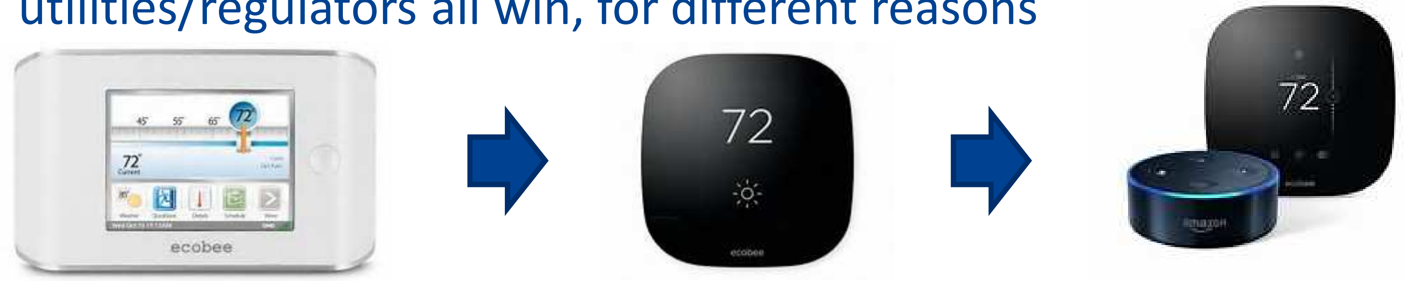
Growing by delivering value to customers

- Just Energy has been operating as an ESP in California since 1998
- Serve close to 100,000 gas and electric customers in California
- Close to 1.5 M residential and commercial customers nationwide
- In a competitive market, the customer chose their energy mix
- One-on-one interactions allow us to find the intersection of what's possible and what's meaningful to customers

amigo energy | Green Star Energy | Hudson Energy | just energy | just energy Foundation | Tara Energy | terrapass RESTORE THE BALANCE

Customers Drive Change

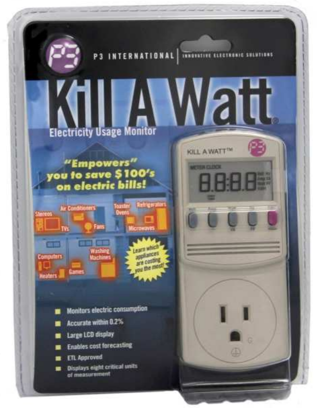
- **Demand for convenience and control led to our partnership with ecobee**
  - Over 50,000 units installed
  - Supports conservation and demand response initiatives – customers and utilities/regulators all win, for different reasons



- **Demand for green energy supports generation projects**
  - Together with our gas product, customers purchase carbon offsets
  - Offer voluntary customer purchase of RECs and carbon offsets in California
  - Perks point program that allow the customer to purchase energy efficient products

Customer Engagement: JE Perks

- Innovative partnership with Energy Earth
- Customer receives loyalty points
- Customer can redeem points for energy efficiency and conservation products
- Focus on value added products in the future

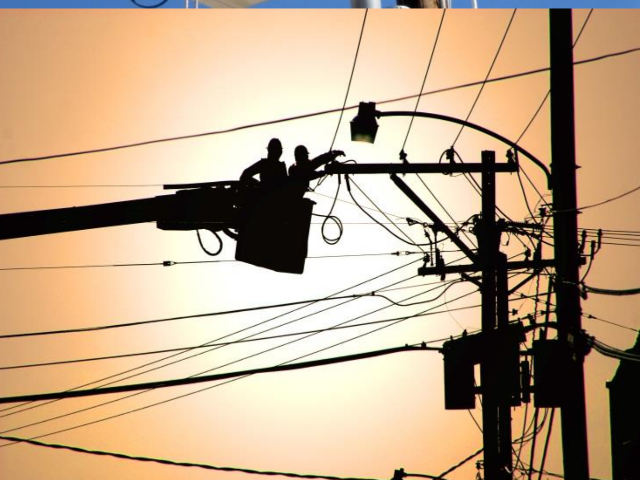


IRP Development – Approach and Methodology

- Just Energy is a small ESP with no self-owned generation
- First IRP plan with focus to comply with reporting requirements
- Used latest approved CPUC Resource Adequacy Year-Ahead Load Forecast to determine assigned load forecast, extended through 2030
- Calculated specific 2030 GHG Emissions Benchmark based on market share
- Utilized the GHG Calculator to estimate the GHG emissions produced based on existing contracts
- Due to system constraints, utilized zip codes to configure amount of customers served in Disadvantaged Communities

Result and Lesson Learned

- Just Energy's current portfolio conforms with future GHG emission reduction needs
- Continue to promote renewable energy through products offered to customers
- Place a greater focus on tracking and maintaining records of resources and emission reduction efforts
- DAC – issues and suggested improvements
- Excellent support from Energy Division Staff
- Improvements to be made before the next IRP cycle
  - Simplified Reporting Process for small LSEs to reduce cost to customers
  - Data access to Net Metering, EV, DR and Energy Storage
  - Account for other types of emission reduction efforts
  - Consider a competitive market approach
  - Create future certainty
  - Further improvements on how to report on DAC designated areas
  - Create DAC programs that benefits all


Bear Valley
Electric Service
A Division of Golden State Water Company

BVES Integrated Resource Plan
An Alternative Plan
Pursuant to D.18-02-018

Filed 7/30/2018

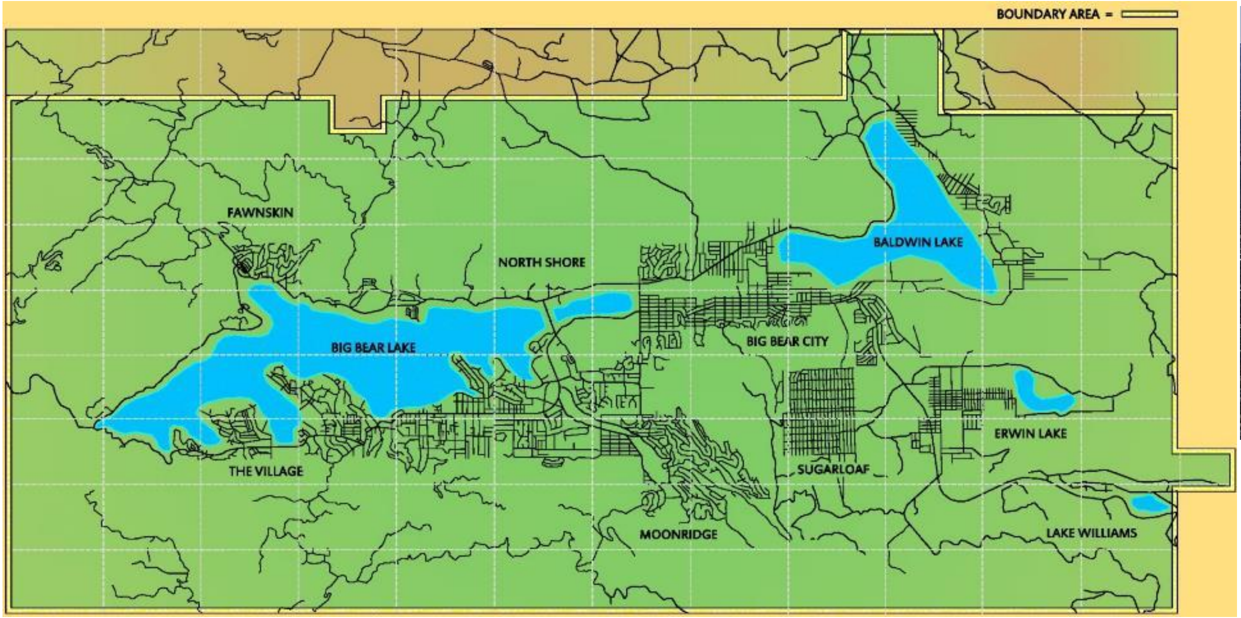
2018 to 2028

https://www.bves.com/media/managed/2018inegratedresourceplan/R_1602007_BVES_2018_Integrated_Resource_Plan.pdf

Prepared by Joseph Phalen,
Energy Resource Manager
August 7, 2018

BVES System Description

- Division of Golden State Water Company.
  - Investor owned utility (IOU) regulated by California Public Utilities Commission (CPUC).
- Service area is 32 square miles of rural and mountainous terrain at approximately 7,000 ft. above sea level in the San Bernardino Mountains of Southern California.
- BVES system is located entirely within the balancing area under the control of the California Independent System Operator (CAISO).
- **BVES Import Capacity is 39 MW via the SCE transmission lines at Goldhill and Radford**
- **BVPP 8.4 MW gas fired generation peak serving plant at 12,900 Btu/KWh**
- **BVES serves approximately 24,000 customers; 22,500 are residential, and 1,500 are commercial.**
- **40% of customers are full time residents and 60% are part time residents. 85% of part-time residents live in LA MSA**
- **BVES service area is driven by tourism (skiing, mountain biking, hiking, mountain sports, boating);early retirement 55-65 age cohort, vacation housing)**
- Most residential customers do not have AC; larger commercial establishments have AC, most residential and commercial customers have gas air heating and water heating.
- Only two major industrial customers. These include Big Bear Area Regional Waste Water Agency (1.1 MW) and Snow Summit (16 MW) ; both customers are interruptible, providing 9 MW interruption capability during BVES coincident peak of 46 MW.
- **BVES DG Customers currently supply 3.4 MW of solar capacity with over 6,000 MWh in production per year.**
- NEM is now closed, BVES anticipates filing alternative rate to NEM in 2018.



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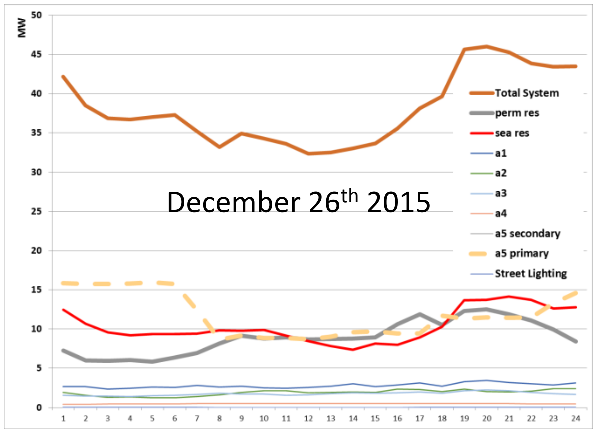
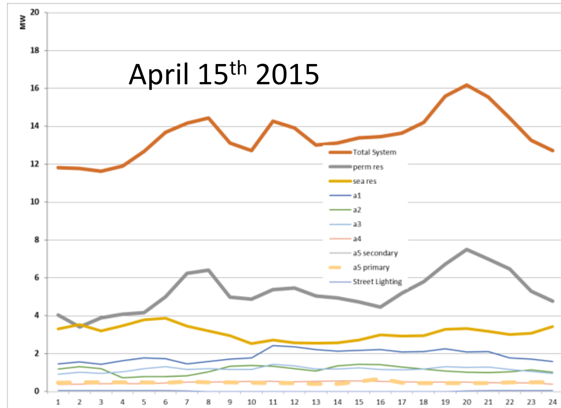
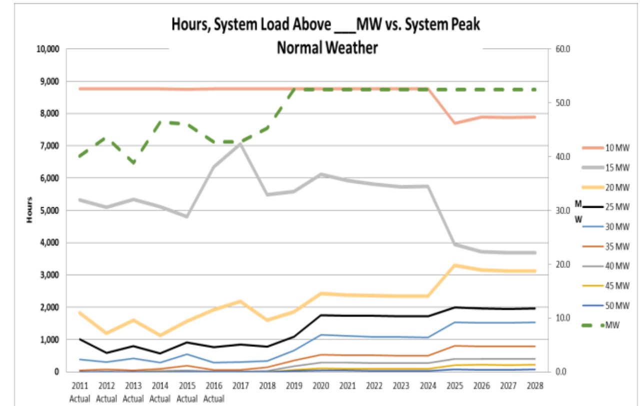
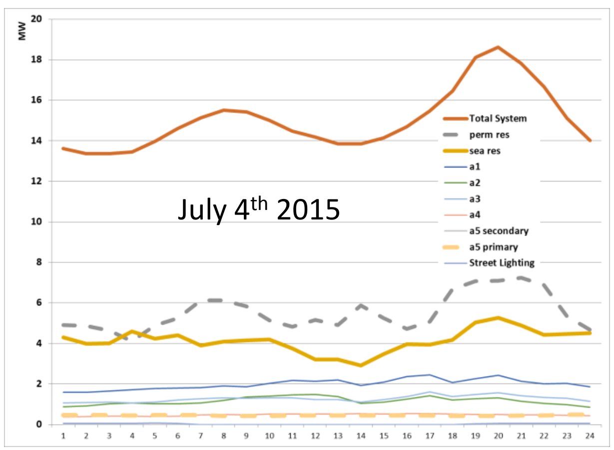
Load Profiles

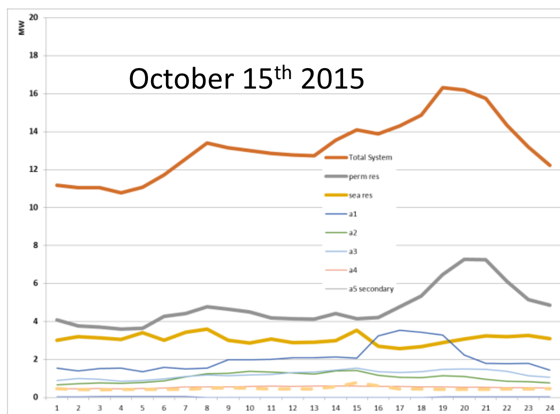
Load patterns across the classes more volatile and diverse as compared to larger utilities.

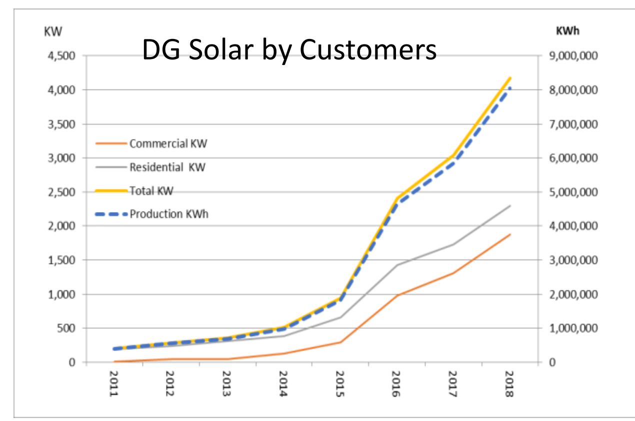












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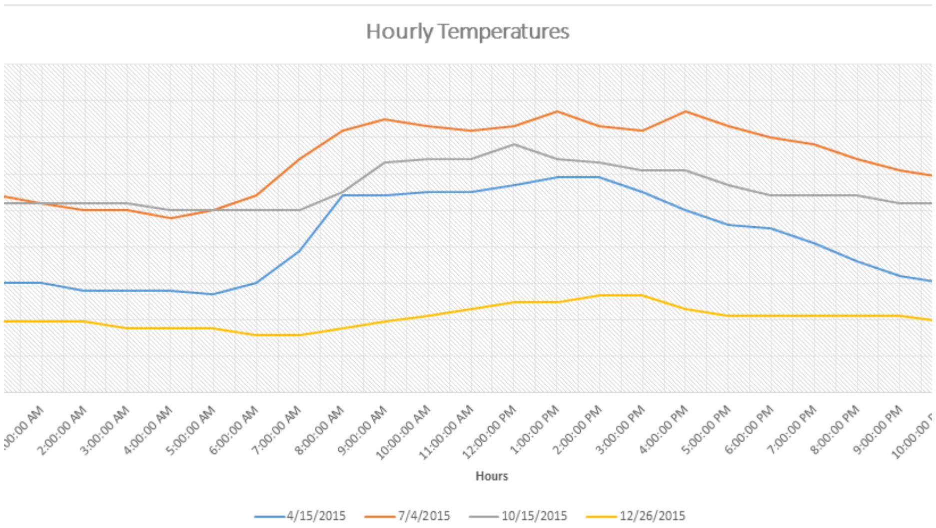
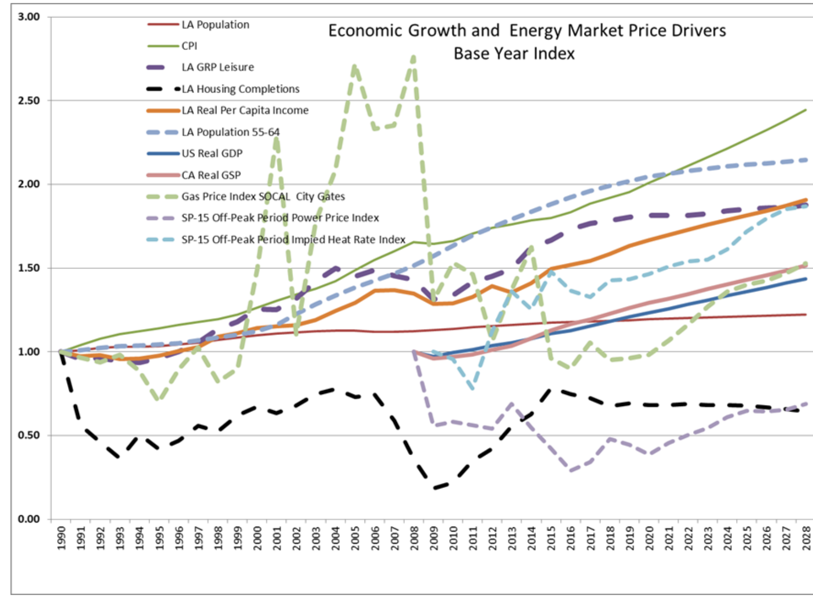
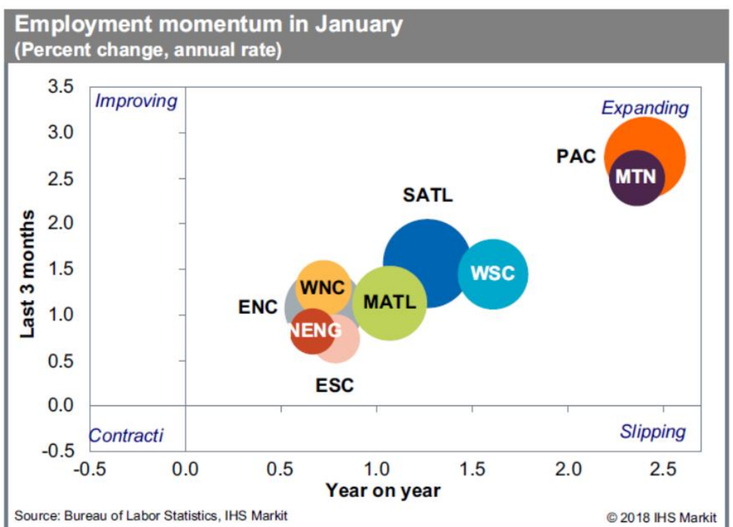
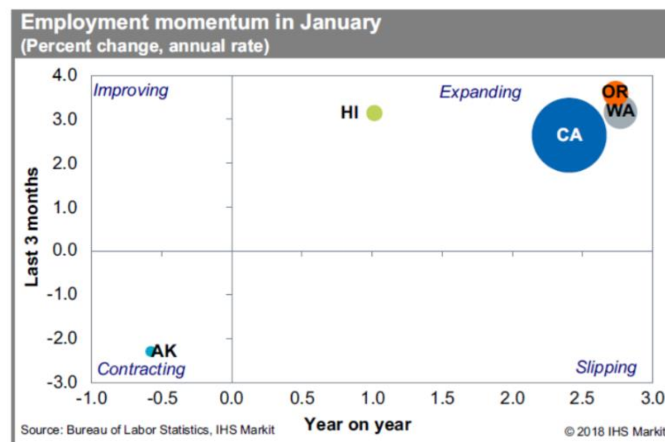
Load Impacting Drivers

- Temperature swings , Los Angeles MSA economy, California economy, the young retirees, and recreation housing



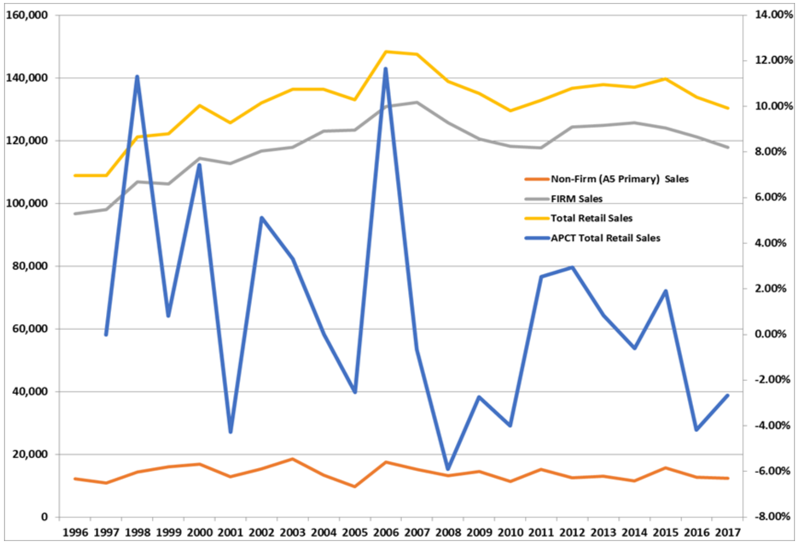


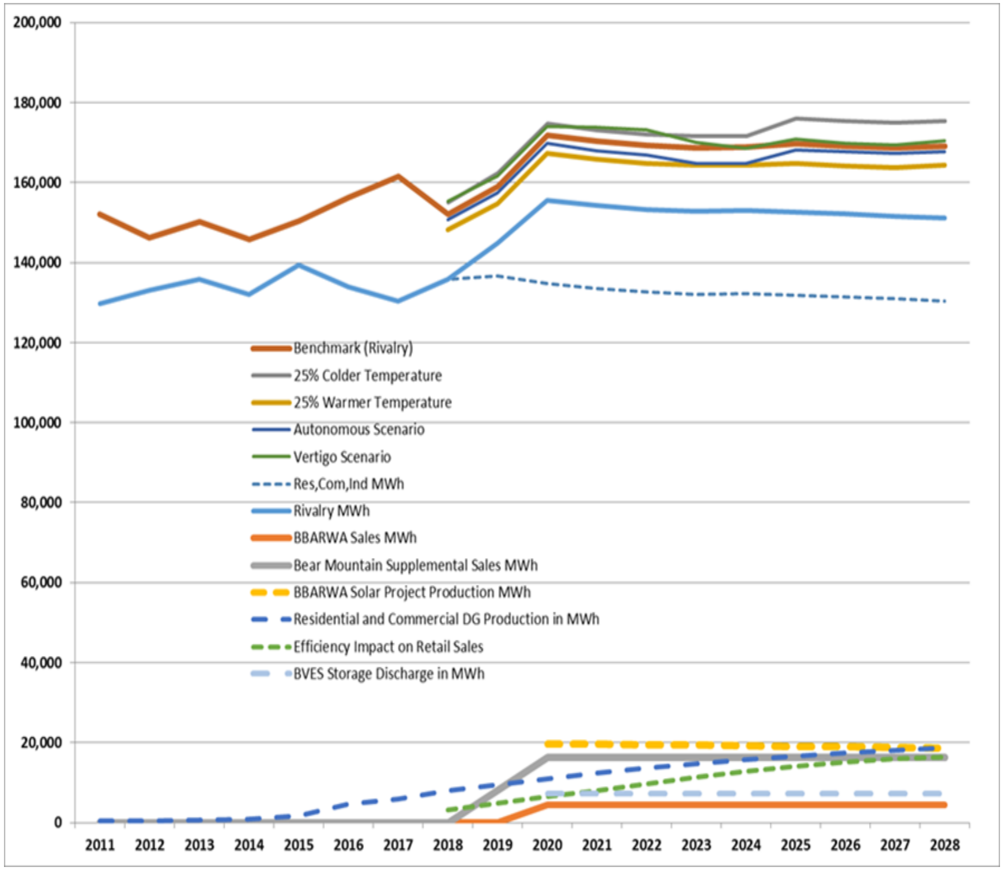




Sales and Energy Requirements

- Volatility in load will continue.
- Efficiency and customer solar generation will offset sales growth.
- Supplemental sales to BBARWA and Snow Summit provide boost to total retail sales by 2020.
- Rivalry ,Vertigo , Autonomous scenario planning ranges allow BVES to plan around economy and policy shifts.





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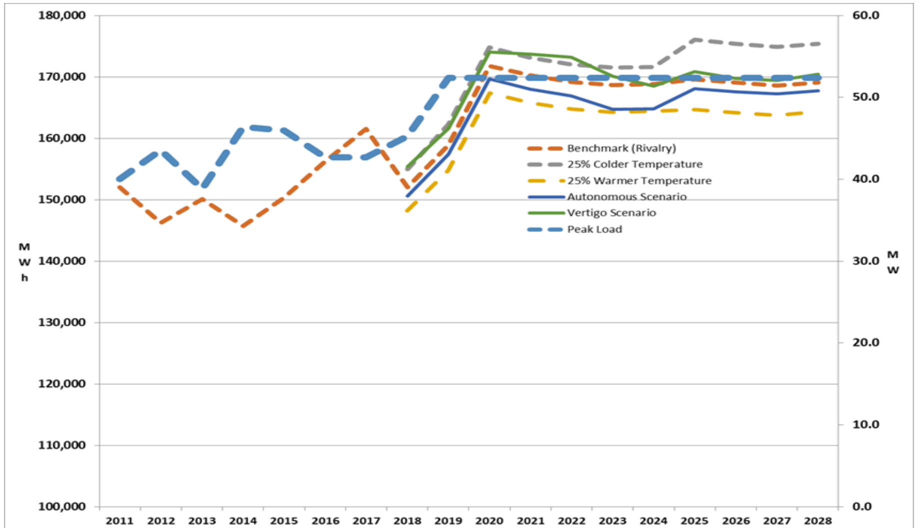
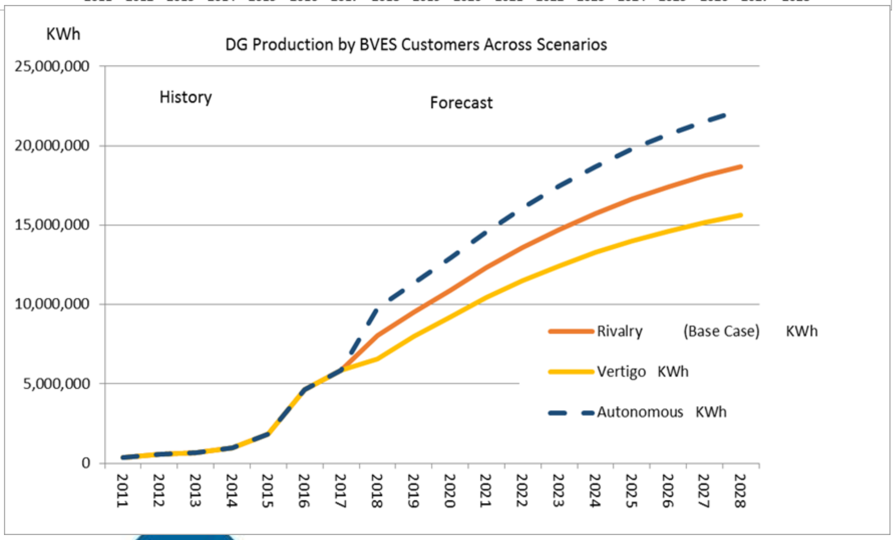
Energy, Peak Load Requirements

- Scenario ranges provide economic and policy ranges
- Higher utilization of capacity tranches over time create opportunity to reduce rates.





	Peak	Energy Req.	Load Factor	Hours BVES System Above:										Sales
Year	MW	MWh	%	5 MW	10 MW	15 MW	20 MW	25 MW	30 MW	35 MW	40 MW	45 MW	**50 MW**	KWh
2011 Actual	40.1	152,027	43.31%	8,760	8,760	5,320	1,817	1,003	376	48	1	0	**0**	133,709
2012 Actual	43.6	146,236	38.29%	8,760	8,760	5,088	1,192	594	302	69	14	0	**0**	128,616
2013 Actual	38.8	150,133	44.16%	8,760	8,757	5,340	1,591	796	418	49	0	0	**0**	132,043
2014 Actual	46.4	145,768	35.85%	8,760	8,760	5,105	1,124	565	281	95	29	4	**0**	128,204
2015 Actual	46.0	150,388	37.33%	8,760	8,755	4,799	1,564	907	539	189	46	3	**0**	132,267
2016 Actual	42.7	156,258	41.77%	8,760	8,760	6,348	1,918	764	288	57	13	0	**0**	137,430
Normal Weather														
2017	42.7	161,565	43.21%	8,760	8,760	7,051	2,189	847	300	57	13	0	**0**	142,098
2018	45.3	152,018	38.32%	8,760	8,759	5,484	1,604	783	335	140	33	1	**0**	133,701
2019	52.4	158,931	34.62%	8,760	8,760	5,587	1,857	1,086	662	344	168	55	**21**	139,781
2020	52.4	171,776	37.42%	8,760	8,760	6,111	2,430	1,758	1,137	536	289	104	**40**	151,078
2021	52.4	170,267	37.09%	8,760	8,760	5,925	2,381	1,741	1,106	521	281	99	**37**	149,751
2022	52.4	169,213	36.86%	8,760	8,760	5,804	2,354	1,729	1,088	512	274	94	**34**	148,824
2023	52.4	168,702	36.75%	8,760	8,760	5,733	2,337	1,725	1,072	504	273	92	**34**	148,375
2024	52.4	168,806	36.77%	8,760	8,760	5,747	2,339	1,726	1,070	503	271	92	**34**	148,466
2025	52.4	169,633	36.96%	8,761	8,252	5,670	2,551	1,748	1,212	607	339	195	**63**	149,194
2026	52.4	169,060	36.83%	8,760	8,409	5,435	2,511	1,745	1,211	598	341	197	**60**	148,690
2027	52.4	168,598	36.73%	8,760	8,410	5,389	2,495	1,737	1,197	595	339	195	**59**	148,283
2028	52.4	169,111	36.84%	8,781	8,427	5,396	2,511	1,752	1,200	601	338	199	**71**	148,735
25% Colder Temperatures														
2018	47.8	154,985	37.00%	8,760	8,758	5,691	1,816	863	414	191	56	7	**0**	136,311
2019	52.4	162,318	35.36%	8,760	8,758	5,759	2,051	1,158	775	412	223	86	**28**	142,760
2020	52.4	174,791	38.08%	8,760	8,760	6,220	2,553	1,799	1285	633	339	150	**56**	153,730
2021	52.4	173,145	37.72%	8,760	8,759	6,004	2,495	1,784	1250	607	330	144	**54**	152,282
2022	52.4	172,042	37.48%	8,760	8,758	5,874	2,457	1,771	1229	596	326	137	**53**	151,312
2023	52.4	171,527	37.37%	8,760	8,758	5,812	2,445	1,768	1221	592	322	134	**52**	150,859
2024	52.4	171,652	37.39%	8,760	8,758	5,821	2,447	1,768	1222	592	322	134	**53**	150,969
2025	52.4	176,046	38.35%	8,761	8,211	5,732	2,791	1,933	1,495	846	461	282	**136**	154,834
2026	52.4	175,411	38.21%	8,760	8,355	5,520	2,767	1,905	1,492	831	467	285	**135**	154,275
2027	52.4	174,901	38.10%	8,760	8,351	5,493	2,748	1,900	1,482	820	459	281	**128**	153,827
2028	52.4	175,369	38.20%	8,781	8,368	5,485	2,758	1,912	1,484	827	460	285	**136**	154,239
25% Warmer Temperatures														
2018	42.5	148,227	39.80%	8,760	8,759	5,121	1,378	679	277	98	9	0	**0**	130,366
2019	52.4	154,796	33.72%	8,760	8,759	5,239	1,622	995	550	293	120	40	**16**	136,144
2020	52.4	167,335	36.45%	8,760	8,760	5,772	2,253	1,676	953	434	230	72	**19**	147,172
2021	52.4	165,786	36.12%	8,760	8,760	5,592	2,199	1,661	925	418	220	67	**19**	145,810
2022	52.4	164,765	35.89%	8,760	8,759	5,444	2,161	1,649	904	409	214	65	**17**	144,912
2023	52.4	164,300	35.79%	8,760	8,759	5,389	2,150	1,644	892	404	211	65	**17**	144,503
2024	52.4	164,457	35.83%	8,760	8,759	5,405	2,153	1,645	893	406	210	65	**17**	144,641
2025	52.4	164,687	35.88%	8,761	8,229	5,450	2,389	1,644	1,020	492	268	139	**45**	144,844
2026	52.4	164,159	35.76%	8,760	8,394	5,216	2,356	1,643	1,012	487	268	141	**46**	144,379
2027	52.4	163,767	35.68%	8,760	8,394	5,183	2,346	1,640	1,001	483	266	135	**45**	144,034
2028	52.4	164,316	35.80%	8,781	8,418	5,178	2,353	1,653	1,002	487	265	139	**49**	144,517

1) Note that although load is interrupted above 50 MW, BVES can serve load up to 52.4 assuming 5 MW battery solution implemented.
Also , load can be served up to 56.4 MW for a duration of 3 hours. The load served above 50 MW has some degree of uncertainty.

Bear Valley Electric Service
A Division of Golden State Water Company

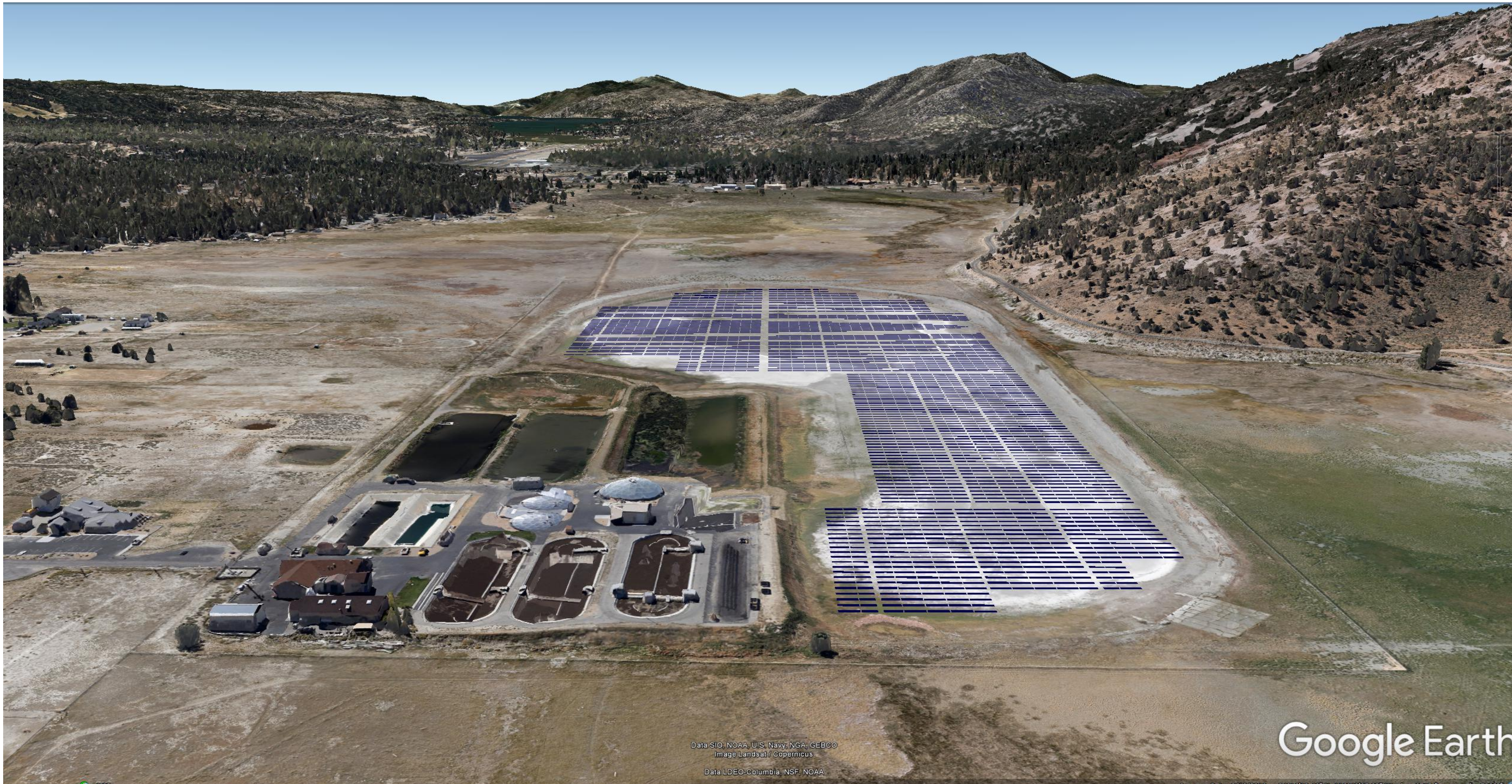
Action Plan over the next 3 years

- **CPUC approval, purchase agreements, land lease agreements, and tariff Approval for the 8 MW Single Axis Tracking System with selected vendor.**
  - Operating by 2020
  - Producing a minimum of 19,631 MWh year 1 …16,125 MWh year 30; average 17,888 MWh per year over 30 yr life.
  - Assume 30 % ITC
  - Annual Revenue requirements average $ 1.2 MM and result in average cost of $67.31 / MWh; 33% below the average all in cost of power.
  - Meets 38% of RPS requirement by 2020 and 27% of RPS by 2028
  - **Reduces emissions by 0.004 MMT /yr.**
- **Negotiate Firm Power (59 month) annual and seasonal (36 month) shaped and fixed volume, 5 contracts, .**
  - Based on assumption that BVES completes solar and battery project and the customer DG solar ,rivalry case , production case comes to fruition.
  - Load shape of import requirements is based on base case with 25% colder than normal temperature, with the battery storage duty cycle where BVES charges during solar production hours at 5 MW per hour for 4 hours and discharges the battery during the peak period 7 to 11 PM.
  - Monthly hourly contract volumes sized at the 90th percentile of colder than normal temperature. This minimizes short position.
  - BVES long positions will be sold back in the real time market. Anticipated timing of long positions occur when spot price forecasts for the month are expected to exceed the indicative pricing of the bids. This is due to diversity in load patterns between BVES and CAISO.
  - RFP Sent out May 10th, 2018, requesting bids for annual fixed volumes, and hourly shaped contracts for the annual contracts and fixed volume , variable volume, and hourly shaped contacts for the Winter seasonal period November to February .
  - Finalists bidders selected to negotiate EEI agreements with BVES and BVES will file for the PPA contract approvals in August, 2018.
  - Finalists will provide refresh bids and BVES will refresh price analytics .
  - Upon CPUC approval of PPAs, BVES will request final refresh from the finalists and select the final annual and seasonal product along with the winning bids for the selected products.
  - The monthly assessment of spot prices in the future for power and gas and the indicative bids received indicate that the purchase power contracts should be pursued as the all in delivered price of imported is less than the cost of BVPP supplied power.
  - The BVPP will supply power requirements above the SCE transmission capacity to BVES plus the battery discharge flow (when available) .
  - **The finalists bidders all have indicated that their California supplies are carbon free.**
  - **Besides hedging power prices, these contracts could reduce carbon emissions from 0.01008 MMT of emissions to 0.00011 MMT.**

Bear Valley Electric Service
A Division of Golden State Water Company

Overhead View from East

Bear Valley
Electric Service
A Division of Golden State Water Company



Action Plan over the IRP planning Period

- **Finalize technology specification for Lithium Ion 5 MW /20 MWh (4 hour) battery.**
  - Operating by 2020
  - May co-commission battery project with solar project to gain 30% ITC if completed by 2020 or 26% ITC if completed in 2021.
  - Worked with Fractal, storage engineering consulting firm, to estimate benefits and to determine best duty cycles and technologies.
  - Benefits of battery should return sizable net savings relative to investment for BVES customers.
  - Benefits include arbitrage energy supply opportunities across time periods of the day, increase BVES capacity through load shifting, reduced RA expenditures through load shape conditioning , accommodates solar production from Bear Valley proposed project and customers solar DG, reduces interruption of interruptible customer 's load.
  - Will leverage success of solar projects.
  - Will leverage success of the Snow Summit substation capacity expansion , allowing for more reduction of emissions as Snow Summit diesel generation with capacity of 12 MW is replaced by BVES supply.
  - Will submit RFP for battery project by end of 2018, anticipated to be 5 MW/20 MWh battery solution.
  - Will file for CPUC approval through advise letter filing if bidding results are favorable.

- **Expand substation capacity at Snow Summit by 17 MW (2, 10 MW substations replace 3 MW existing substation).**

- Prepared benefit analysis for Snow Summit substation expansion illustrating that under numerous snow making load requirements observed over the last 11 years and under varying diesel prices and diesel generation heat rates with the A5 Primary rate and the proposed added facilities charge, Snow summit should realize annual benefits ranging from $ 600,000 to $2,000,000 per year in fuel cost savings.
- **Additional benefits include reduction in emissions of 0.0122 MMT of carbon emissions.**
- The emissions reduction is valued at $192,000 /yr. assuming carbon allowance pricing forecasted by consulting firm .
- Customers will realize a reduction in average fixed costs as $1,000,000 per year in revenue will cover fixed costs of capacity, assumed to be a sunk cost.

Bear Valley Electric Service
A Division of Golden State Water Company

Action Plan over the IRP planning Period

- **The Transportation Electrification Pilot project (Make Ready 50 installations, TOU 50 installations)**
  - On June 20, 2017, BVES has already applied for approval of its 2017 Transportation Electrification proposal (17-06)
  - The pilot project will fund the infrastructure labor and materials cost for up to 50 charging stations for a make ready program
  - The program fund up to 50 residential and commercial infrastructure set up for residential customer EV chargers
  - The program develop a TOU gram for EV charging accounts only to incentives customers to charge their vehicles during the super off-peak period, during high solar power production times, and will charge higher rates during other times of the day, with the highest rate charged during BVES peak period
  - BVES will monitor the success of this program and use the program to gain insight into customers EV charging behavior for the BVES service area
  - This should create a new end-use for electricity from BVEs during the daytime, increasing the load factor for BVES, and reduce carbon emissions for Southern California. The reshaping of the load shape could also reduce the cost of supply for customers.

  - **Market for EV Charging in Big Bear Lake**
  - With approximately 6,000,000 visitors to BVES each year and given the central location of BVES within the tourist spots of Southern California, it is imperative for BVES to test the market for EV charging stations.
  - This could add 4,500 MWh per 1,000 charged Electric vehicles per year to retail sales . Adding $158,000/yr. in revenues net energy costs.
  - This could create $ 1,500,000 per year in savings for group of 1,000 EV users , full time equivalent., assuming the customer charges at super peak period (solar generation hours) .
  - **Will reduce emissions by 0.005 MMT for every 1,000 cars per year.**
  - Pending CPUC Approval
  - Not in the IRP retail sales forecast because of the uncertainty of load and to avoid over procurement of power contracts.

Bear Valley Electric Service
A Division of Golden State Water Company

Action Plan over the IRP planning Period

- **Supplemental Sales to BBARWA Created by Bear Valley Solar Project on BBARWA Property (Baldwin Lake),dry bed**
  - Bear Valley 8 MW Single Axis Tracking System Solar Project requires 60 acres , provided by BBARWA (Baldwin Lake) ; avoids BVES having to utilize commercial property at $1 million /acre.
  - BBARWA estimated supplemental consumption will be 4,473 MWh per year .
  - This was sold to BBARWA prior to the construction of the BBARWA's 1.1 MW gas fired generation facility.
  - Solar project will replace gas fired generation supplied power with solar supplied power for approximately 38% of consumption, due to steady load pattern of BBARWA throughout the 24 hour day.
  - An alternative rate will be developed for BBARWA (Allowed under Section 8.2.3 of General Oder 96-B). This will be in addition to the Bureau of Land Management land lease rate .
  - BBARWA serves all BVES customers as a waste water treatment facility . All customers share in the savings created by the supplemental sales to BBARWA.
  - **Emissions reduced by** the substitution of 38% BBARWA gas fired generation with Bear Valley Solar project output. This equates to ((117 lbs/mmbtu)*(12,900 Btu/Kwh)*(38 %*4,473,000 Kwh)/(2,205 lbs./ton) = 1,163 tons=**0.0011634 MMT / year.**
  - The supplemental sales to BBARWA from the Bear Valley Solar Project begins with the operation of the solar project.

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Action Plan over the IRP planning Period

- **BVES will revisit efficiency programs for residential and small commercial; for now, BVES will continue programs for the low income customers who need the boost from the program to make the appliance efficiency investment.**
  - BVES current programs include Low Income Efficiency (LIEE) and Energy Savings Assistance (ESA) and California Alternative Rates (CARE).
  - BVES Residential Energy Efficiency Program offers lighting and high efficiency appliance rebates.
  - For commercial customers , BVES offers rebates for lighting improvements including florescent fixtures lighting retrofits, specialty screw-in lamps, low wattage T8 lamps, exterior linear florescent fixtures, LED exit signs, occupancy sensors, time clocks and more.
  - BVES lighting load is highly is a significant driver of the BVES peak demand, Energy efficient lighting results in a significant reduction in peak demand for the BVES system.
  - A future efficiency program, under consideration at this time ;but not included in the base case forecast for the IRP , involves changing out 47% of the residential 40 + watt bulbs with the 9 watt LED bulbs.
  - This would involve changing out 147,402 bulbs for a cost of $ 765,189 ; achieving 16,000 MWh in reduction per year ,saving $400,000 / year for participating customers .
  - This would also reduce the peak by 1.6 MW, avoiding $1,200,000 in capacity expansion capital costs in the future.
  - **This would reduce emissions by 0.002 MMT / year.**

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Action Plan over the IRP planning Period

- **BVES Demand Response through Interruption Program will provide significant load control on the system.**
  - BVES will have the Summit Ski resort customer (A5 Primary) as an interruptible customer with 9 MW interruptible load , with a BVES system peak of 45 MW. Providing up to 20% reduction in peak , when needed.
  - If the Snow Summit Substation expansion comes to fruition , BVES will have 18 MW of interruptible load. This will also reduce the RA requirement on the CAISO system by up to 40%.
  - This capacity along with 5 MW battery will allow BVES to reduce system or local RA by 23 Mw for each month, creating a savings of about $1.3 Million per year in RA costs from 2020 onward.

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BVES Energy Supply Portfolio

Table 25: BVES Supply of Energy Requirements in Percent

	Energy Efficiency	Customer DG Solar	Utility owned Solar	Gas Fired Gen BVPP	Interruption of Sales	Imported CAISO Power	Line Losses	Total Energy Required for IRP Planning
2018	1.74%	4.48%	0.00%	0.00%	0.00%	84.70%	9.08%	100.00%
2019	2.56%	5.08%	0.00%	0.04%	0.00%	84.75%	7.57%	100.00%
2020	3.14%	5.32%	9.63%	0.07%	0.00%	73.96%	7.88%	100.00%
2021	3.83%	5.97%	9.51%	0.07%	0.00%	72.87%	7.75%	100.00%
2022	4.65%	6.53%	9.35%	0.06%	0.00%	71.78%	7.63%	100.00%
2023	5.44%	6.99%	9.18%	0.06%	0.00%	70.81%	7.52%	100.00%
2024	5.99%	7.39%	9.02%	0.06%	0.00%	70.11%	7.44%	100.00%
2025	6.54%	7.75%	8.87%	0.13%	0.00%	69.32%	7.40%	100.00%
2026	7.04%	8.05%	8.76%	0.13%	0.00%	68.71%	7.31%	100.00%
2027	7.39%	8.33%	8.66%	0.13%	0.00%	68.24%	7.26%	100.00%
2028	7.52%	8.52%	8.51%	0.13%	0.00%	67.77%	7.55%	100.00%

Table 26: BVES Supply of Energy Requirements Aggregated in Percent

	Energy Efficiency	Renewables	Gas Fired Gen BVPP	Imported CAISO Power	Line Losses	Total Energy Required for IRP Planning
2018	1.74%	4.48%	0.00%	84.70%	9.08%	100.00%
2019	2.56%	5.08%	0.04%	84.75%	7.57%	100.00%
2020	3.14%	14.95%	0.07%	73.96%	7.88%	100.00%
2021	3.83%	15.48%	0.07%	72.87%	7.75%	100.00%
2022	4.65%	15.88%	0.06%	71.78%	7.63%	100.00%
2023	5.44%	16.17%	0.06%	70.81%	7.52%	100.00%
2024	5.99%	16.41%	0.06%	70.11%	7.44%	100.00%
2025	6.54%	16.61%	0.13%	69.32%	7.40%	100.00%
2026	7.04%	16.81%	0.13%	68.71%	7.31%	100.00%
2027	7.39%	16.99%	0.13%	68.24%	7.26%	100.00%
2028	7.52%	17.03%	0.13%	67.77%	7.55%	100.00%

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CA Energy Supply Gen. Assumption

Table 28: California Generation by Fuel Type in Percent

CA Gen by Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas CC	34.42%	33.10%	30.34%	27.59%	25.16%	24.14%	23.88%	26.85%	28.51%	28.52%	28.40%
Gas CT	4.95%	4.96%	4.88%	4.92%	4.95%	4.88%	5.04%	5.23%	5.28%	5.30%	5.35%
Gas ST	0.70%	0.56%	0.54%	0.18%	0.23%	0.28%	0.31%	0.39%	0.44%	0.38%	0.39%
Coal–advanced	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Coal–conventional	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	8.52%	8.18%	7.79%	7.92%	7.71%	6.99%	6.92%	2.22%	0.00%	0.00%	0.00%
Hydro	14.26%	13.26%	12.93%	12.74%	12.56%	12.33%	12.29%	12.41%	12.34%	12.29%	12.23%
Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wind	6.79%	7.01%	8.61%	9.90%	11.09%	12.24%	12.27%	12.46%	12.59%	12.70%	12.78%
Solar PV	18.49%	21.16%	23.36%	25.40%	27.32%	28.38%	28.44%	29.38%	29.64%	29.65%	29.56%
Solar CSP	2.37%	2.35%	2.29%	2.25%	2.21%	2.17%	2.16%	2.17%	2.16%	2.15%	2.13%
Biomass	2.55%	2.57%	2.54%	2.51%	2.49%	2.45%	2.47%	2.56%	2.60%	2.62%	2.65%
Geothermal	7.58%	7.52%	7.41%	7.27%	6.98%	6.82%	6.90%	7.06%	7.21%	7.16%	7.27%
Pumped storage	-0.61%	-0.64%	-0.65%	-0.63%	-0.61%	-0.60%	-0.58%	-0.62%	-0.63%	-0.63%	-0.62%
Batteries (≥ 4 hour duration)	-0.01%	-0.03%	-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.11%	-0.13%	-0.14%	-0.15%
Total generation (GWh)	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

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CA Energy Supply Gen. Assumption

Table 29: BVES Energy Composition Assuming Imported Power Content Equals to California Generation Mix

Year	Energy Efficiency	Renewables	Gas Fired Gen	Hydro	Nuclear	Line Losses	Total Energy Required for IRP Planning
2018	1.7%	36.0%	33.9%	12.1%	7.2%	9.1%	100.0%
2019	2.6%	38.9%	32.8%	11.2%	6.9%	7.6%	100.0%
2020	3.1%	47.1%	26.5%	9.6%	5.8%	7.9%	100.0%
2021	3.8%	49.5%	23.9%	9.3%	5.8%	7.8%	100.0%
2022	4.6%	51.3%	21.8%	9.0%	5.5%	7.6%	100.0%
2023	5.4%	52.6%	20.8%	8.7%	4.9%	7.5%	100.0%
2024	6.0%	52.6%	20.5%	8.6%	4.9%	7.4%	100.0%
2025	6.5%	53.3%	22.6%	8.6%	1.5%	7.4%	100.0%
2026	7.0%	53.5%	23.6%	8.5%	0.0%	7.3%	100.0%
2027	7.4%	53.5%	23.5%	8.4%	0.0%	7.3%	100.0%
2028	7.5%	53.4%	23.3%	8.3%	0.0%	7.6%	100.0%

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BVES Local Energy Versus System Ref.

Table 30: BVES Energy Requirement from Local Supply Only Composition

Year	Energy Efficiency	Renewables	Gas Fired Gen BVPP	Total Energy Required for IRP Planning
2018	28.0%	72.0%	0.0%	100.0%
2019	33.3%	66.2%	0.5%	100.0%
2020	17.3%	82.3%	0.4%	100.0%
2021	19.8%	79.9%	0.3%	100.0%
2022	22.6%	77.1%	0.3%	100.0%
2023	25.1%	74.6%	0.3%	100.0%
2024	26.7%	73.1%	0.3%	100.0%
2025	28.1%	71.4%	0.6%	100.0%
2026	29.4%	70.1%	0.5%	100.0%
2027	30.2%	69.3%	0.5%	100.0%
2028	30.5%	69.0%	0.5%	100.0%

Table 31: Proportion of Gross Energy Generation in Reference System Portfolio in 2030

Resource	Percentage of Gross GWh
Renewables	44.9%
Gas	23.4%
Energy Efficiency	11.7%
Hydro	9.0%
CHP	5.3%
Net Imports	3.9%
Nuclear	1.8%

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BVES Portfolio Exceeds Emissions Target

Table 33: Carbon Emissions (MMT) for Bear Valley Electric, Included Import Power Content Scenario

Year	Bear Valley Power Plant (1)	Renewables (2)	Imported Power from CA Market (3)	Total Emissions (4)= (1)+(2)+(3)	Imported 0 Emissions Power Alternative (5)	Total Emissions with 0 Emissions Imported Power (6)	GHG Emissions 2030 Target for BVES (7)
2018	0.00000	0.00000	0.02236	0.02236	0.00000	0.00000	0.027
2019	0.00003	0.00000	0.02099	0.02102	0.00000	0.00003	0.027
2020	0.00006	0.00000	0.01453	0.01459	0.00000	0.00006	0.027
2021	0.00005	0.00000	0.01272	0.01277	0.00000	0.00005	0.027
2022	0.00005	0.00000	0.01138	0.01143	0.00000	0.00005	0.027
2023	0.00005	0.00000	0.01059	0.01064	0.00000	0.00005	0.027
2024	0.00005	0.00000	0.01023	0.01028	0.00000	0.00005	0.027
2025	0.00011	0.00000	0.01087	0.01098	0.00000	0.00011	0.027
2026	0.00011	0.00000	0.01094	0.01105	0.00000	0.00011	0.027
2027	0.00010	0.00000	0.01045	0.01056	0.00000	0.00010	0.027
2028	0.00011	0.00000	0.00997	0.01008	0.00000	0.00011	0.027

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BVES Installed Capacity Portfolio

Table 34: BVES Installed Capacity in MW

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Imported CAISO Power	Battery	Shed Demand Response	Total Capacity
2018	0.86	4.2		8.4	39		15.0	67.43
2019	1.31	4.9		8.4	39		15.0	68.66
2020	1.77	5.7	8.0	8.4	39	5.0	28.0	95.84
2021	2.17	6.4	8.0	8.4	39	5.0	28.0	96.97
2022	2.65	7.1	8.0	8.4	39	5.0	28.0	98.11
2023	3.14	7.6	8.0	8.4	39	5.0	28.0	99.18
2024	3.50	8.2	8.0	8.4	39	5.0	28.0	100.08
2025	3.85	8.7	8.0	8.4	39	5.0	28.0	100.90
2026	4.17	9.0	8.0	8.4	39	5.0	28.0	101.62
2027	4.40	9.4	8.0	8.4	39	5.0	28.0	102.20
2028	4.52	9.7	8.0	8.4	39	5.0	28.0	102.63

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BVES Vs. System Portfolio Capacity

Table 36: BVES Installed Local Capacity in Percent

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Battery	Shed Demand Response	Total Capacity
2018	3.02%	14.67%	0.00%	29.55%	0.00%	52.76%	100.00%
2019	4.43%	16.67%	0.00%	28.32%	0.00%	50.58%	100.00%
2020	3.11%	9.97%	14.08%	14.78%	8.80%	49.27%	100.00%
2021	3.74%	11.04%	13.80%	14.49%	8.63%	48.30%	100.00%
2022	4.49%	11.94%	13.53%	14.21%	8.46%	47.37%	100.00%
2023	5.22%	12.70%	13.29%	13.96%	8.31%	46.52%	100.00%
2024	5.73%	13.39%	13.10%	13.75%	8.19%	45.84%	100.00%
2025	6.23%	13.97%	12.92%	13.57%	8.08%	45.23%	100.00%
2026	6.67%	14.45%	12.78%	13.41%	7.98%	44.71%	100.00%
2027	6.96%	14.87%	12.66%	13.29%	7.91%	44.30%	100.00%
2028	7.11%	15.25%	12.57%	13.20%	7.86%	44.01%	100.00%

Table 37: Recommended System Portfolio for California in 2030

Resource	MW (% total)
Natural Gas	25.9
Solar	21.7
Customer Solar	16.0
Wind	9.3
Hydro (Large)	7.9
Energy Efficiency	7.4
Battery Storage	3.3
Pumped Storage	1.8
Shed Demand Response	1.8
CHP	1.7
Geothermal	1.4
Biomass	0.7
Nuclear	0.6
Hydro (Small)	0.5

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BVES System Portfolio Capacity at Night

Table 38: BVES Installed Capacity Available at BVES Peak in Percent

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Imported CAISO Power	Battery	Shed Demand Response	Total Capacity
2018	1.50%	0.00%	0.00%	14.67%	68.11%	0.00%	15.72%	100.00%
2019	1.97%	0.00%	0.00%	12.57%	58.37%	0.00%	27.09%	100.00%
2020	2.45%	0.00%	0.00%	11.62%	53.97%	6.92%	25.05%	100.00%
2021	2.99%	0.00%	0.00%	11.58%	53.74%	6.89%	24.80%	100.00%
2022	3.63%	0.00%	0.00%	11.50%	53.38%	6.84%	24.64%	100.00%
2023	4.27%	0.00%	0.00%	11.42%	53.03%	6.80%	24.48%	100.00%
2024	4.74%	0.00%	0.00%	11.37%	52.77%	6.77%	24.36%	100.00%
2025	5.19%	0.00%	0.00%	11.31%	52.52%	6.73%	24.24%	100.00%
2026	5.60%	0.00%	0.00%	11.26%	52.30%	6.70%	24.14%	100.00%
2027	5.88%	0.00%	0.00%	11.23%	52.14%	6.68%	24.06%	100.00%
2028	6.04%	0.00%	0.00%	11.21%	52.05%	6.67%	24.02%	100.00%

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Lessons Leaned in this BVE IRP Process

- Opportunity to build 8 MW Solar Single Tracking system with high load factor made available through public lands and allowed BVES to save money for customer.
- Synergy in helping largest industrial customer by replacing their diesel generation with BVES supply (13 MW) ; reducing their energy cost, energy cost for all customers, carbon emissions for all BVES customers.
- The 5 MW /20 MWh battery solution creates many significant savings opportunities and allows BVES to accommodate more solar and low cost energy in the supply portfolio.
- The battery allows BVES to reshape the energy requirements, creating energy cost savings through better shaped contracts.
- As the capacity utilization of the BVES supply increases, the energy requirements are more critical to the BVES portfolio planning process in terms of reducing costs for customers through hedging of both firm and non-firm retail sales and reducing the carbon emissions rate.
- In this current power procurement process, BVES has learned that it is crucial that BVES remain diligent in the bidder selection process on the contract guarantees and on the bidder credit ratings. This process is as important as the evaluation of the price bids for the 36 months contracts and 59 months contracts.
- Average supply cost reduction and cleaner energy supply are compatible through creative synergies of technologies.

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Questions?

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Liberty CalPeco

IRP Summary

August 7, 2018

Liberty CalPeco IRP Summary

- Liberty CalPeco's situation differs from that of other California IOUs, which provides both challenges and opportunities.
- Liberty CalPeco is committed to becoming 100% renewable as early as 2020 with a mix of low-cost renewable and battery resources.
- Liberty CalPeco's long-term plan to become 100% renewable involves a strategy that best serves its customers on factors like affordability, reliability, and a reduction in GHG emissions.
- Liberty CalPeco's long-term plan is consistent with the projects it has been developing over the last few years.

Liberty CalPeco Has Unique Resource Requirements

- Liberty CalPeco is located in the NV Energy Transmission Balancing Authority Area (“BAA”) and not the CAISO BAA.
  - CAISO resources are not readily available to Liberty CalPeco due to limited transmission resources from California to its service territory.
  - The generation portfolio in Nevada is significantly different from that of California, and Nevada is not seeking to secure the same level of green resources.
- Liberty CalPeco is a winter-peaking load with high levels of vacation homes and negligible large commercial and industrial loads other than ski resorts.
- Many of Liberty CalPeco’s largest customers have made commitments to moving to 100% renewable, including Squaw Valley, Vail, the City of South Lake Tahoe, and the Lake Tahoe Unified School District.
- Rooftop solar is limited in the Lake Tahoe region due to much of the service territory being in forested areas.

Liberty CalPeco’s Current Portfolio

- Liberty CalPeco’s load is currently served by the Liberty CalPeco-owned 50 MW Luning Solar Facility and an existing energy services agreement with NV Energy that provides the remaining load.
- A second Solar Facility, the Liberty CalPeco-owned 10 MW Turquoise Solar Facility, is expected to come online at the end of the year.
- Liberty CalPeco also has a storage application (Alpine County Battery) pending with the CPUC and plans to include a microgrid project in its upcoming GRC.
- Liberty CalPeco’s supply agreement with NV Energy expires in May 2019.

Liberty CalPeco's Plan

- Short-Term Bridging Agreement
  - To replace the NV Energy agreement, Liberty CalPeco will issue a solicitation for a short-term, all requirements energy services agreement as a bridge until Liberty CalPeco can secure utility-owned renewable generation through a competitive process.
- Long-Term Plan
  - Liberty CalPeco will issue solicitations for the acquisition of up to 150 MW of additional renewable generation supply for its customers
  - Focus will be on low-cost wind and solar resources that qualify for federal tax incentives, similar to what Liberty CalPeco utilized for its Luning and Turquoise Solar Facilities
  - Liberty CalPeco will also consider both co-located and stand-alone energy storage projects to allow for higher penetration of renewables
  - Liberty CalPeco is also considering expanding its Energy Efficiency and Solar Initiative programs

Why Liberty CalPeco's Plan Makes Sense

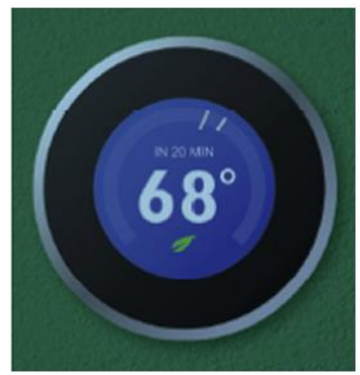
- It is strategically important for Liberty CalPeco to take direct control of and develop generation capabilities to meet customer expectations and regulatory requirements.
- Liberty CalPeco cannot rely on procuring energy from the Nevada market because the Nevada generation portfolio is significantly different from California's generation portfolio, and Nevada is not seeking to secure the same level of green resources.
- Liberty CalPeco must secure local generation within the NVE BAA that does not require extensive investment in new transmission resources.
- Liberty CalPeco needs to move quickly. Timing is a factor because the longer it takes to secure the resources, the lower the available tax credits, resulting in higher costs of energy for Liberty CalPeco customers.
- Liberty CalPeco customers have shown great interest in Liberty CalPeco increasing its use of renewable power. Liberty CalPeco has implemented a Green Tariff going into effect in September.
- Climate change has been identified as the greatest threat to Lake Tahoe.

What Liberty CalPeco Needs From the Commission

- The authority to secure the short-term bridging supply agreement before the NV Energy Services Agreement expires in May 2019.
- The authority to undertake a competitive process to secure Liberty CalPeco ownership of long-term supply and storage options.
- Expedited processing of Liberty CalPeco’s procurement plan, so that the agreements may be approved ahead of any CPUC consolidated plan for LSEs that operate within CAISO.

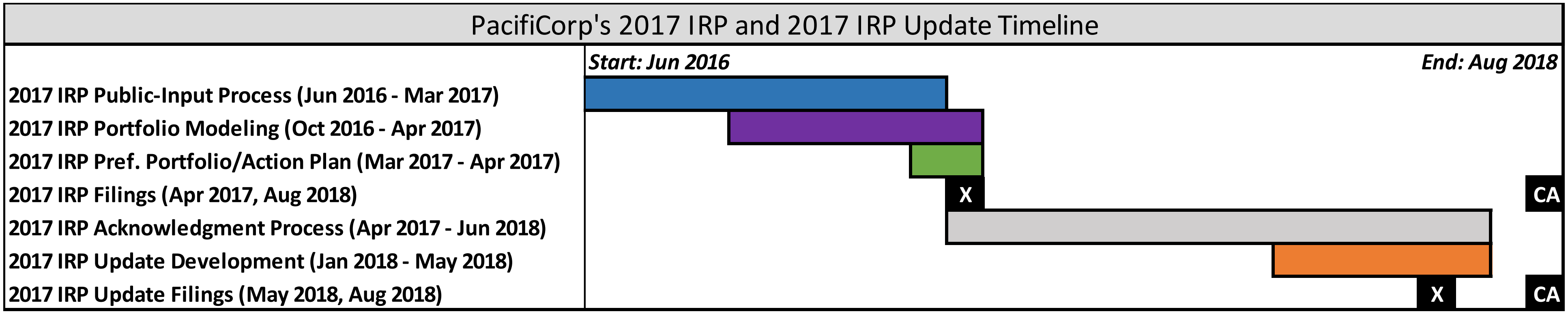
PacifiCorp 2017 IRP
California Public Utility Commission IRP Workshop
August 7, 2018



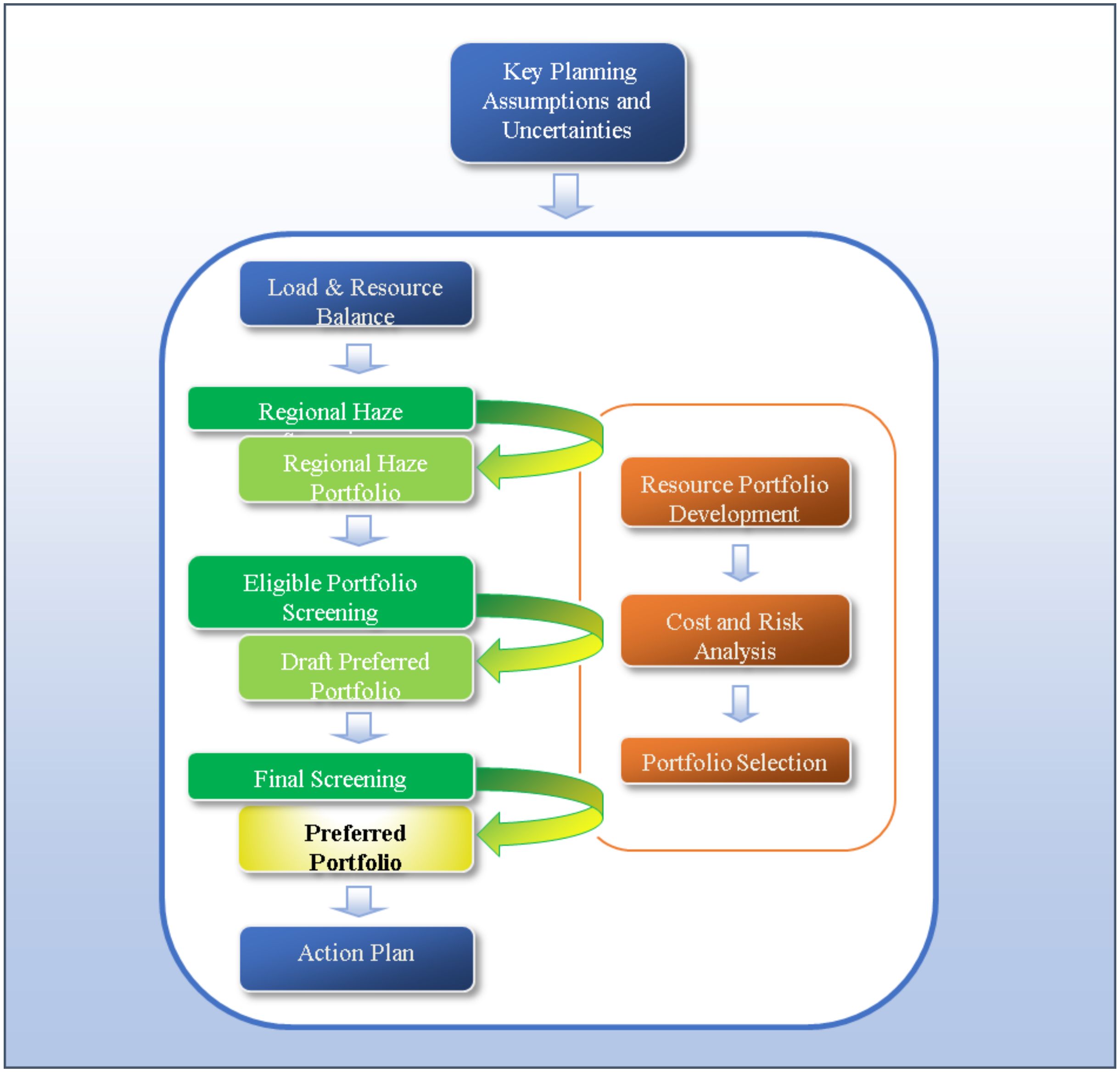
PACIFICORP
POWERING YOUR GREATNESS

Introduction



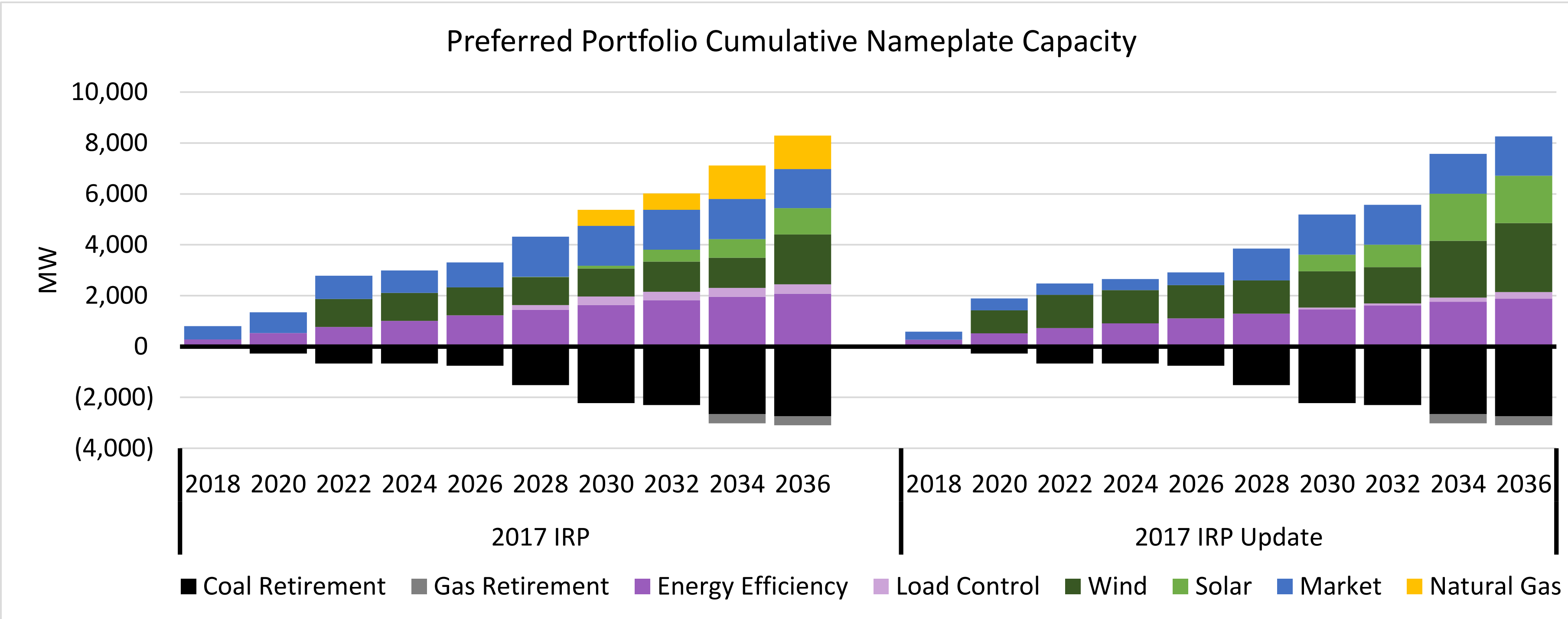
- PacifiCorp serves over 1.7 million customers in six western states (CA, ID, OR, UT, WA, and WY).
- PacifiCorp serves approximately 45 thousand customers in California.
- PacifiCorp operates its system as a single system and develops a single system-wide resource plan.
- PacifiCorp develops its system-wide IRP on a two-year cycle.
  - The 2017 IRP was finalized April 4, 2017 and filed again in California on August 7, 2018.
- PacifiCorp develops an IRP Update in off-cycle years.
  - The 2017 IRP Update was finalized May 1, 2018 and filed again in California on August 7, 2018.
- Stakeholders have opportunities to influence PacifiCorp's IRP, during the public-input process and submit comments to state commissions during the acknowledgment and review process.

Portfolio Development



- Objective: Identify the best mix of resources to serve customers in the future (20-year planning period).
- The best mix of resources is identified through analysis that measures costs and risks.
- The least-cost, least-risk portfolio, designated as the preferred portfolio, drives specific action items (*i.e.*, issuance of an RFP) with a focus on the first two to four years of planning period.

Preferred Portfolio Highlights



- By 2021, over 1,300 MW of wind (subsequently reduced to 1,150 MW of wind), nearly 1,000 MW of repowered wind (not shown above), and a new 140-mile, 500-kV transmission line from Aeolus to Bridger/Anticline in Wyoming (collectively referred to as Energy Vision 2020).
- Through 2036, the preferred portfolio includes over 2,700 MW of new wind, 1,860 MW of new solar, and 1,877 MW of new energy efficiency.
- With reduced loads and declining costs for renewable resources, informed in part by recent request for proposals, the 2017 IRP Update preferred portfolio does not include any new gas-fired resources.
- Through 2036, the preferred portfolio assumes coal capacity is reduced by 3,650 MW.

Action Plan

- PacifiCorp's 2017 IRP includes 18 distinct action items that address renewable resources, transmission, market purchases, demand-side management, and coal resources. Key action items are set forth below:
  - Implementation of the Energy Vision 2020 wind repowering project with updated economic analysis and pre-approval regulatory filings.
  - Implementation of the Energy Vision 2020 new wind and transmission projects with issuance of a request for proposals for new wind and pre-approval regulatory filings.
  - Acquisition of energy efficiency resources consistent with targets set forth in the preferred portfolio.
  - Continued analysis of specific coal-unit retirement and natural-gas conversion alternatives.
- Disadvantaged Communities
  - PacifiCorp does not have any disadvantaged communities as defined by the California Public Utility Commission.
- GHG Planning Targets
  - GHG planning targets set forth a standard for PacifiCorp, established June 2018, which serve as a planning instrument and not a compliance obligation.
  - From 2017 through 2036, PacifiCorp's physical system CO_2 emissions are projected to fall by 22 percent (from 39.5 MMT to 30.8 MMT)—emissions in all years are well below PacifiCorp's 1990 emissions (approximately 46 MMT).
  - A decline in system emissions is consistent with the declining targets in California's cap-and-trade program.
  - Reduced emissions attributable to PacifiCorp's California service territory and procurement of allowances, as necessary, will facilitate meeting PacifiCorp's recently defined GHG planning targets.

Energy Vision 2020

- Wind Repowering
  - Safe-harbor equipment purchases in December 2016 are being used to re-qualify existing wind facilities for production tax credits (100%).
  - Modern technology and longer blades will increase annual energy production by approximately 26%.
  - Repowering resets the expected useful life of these wind facilities (assumed to be 30 years), which equates to a life extension of between 10-13 years, depending upon the facility.
  - Present-value net customer benefits are conservatively estimated at $273 million (assuming no value for renewable energy credits and no value for incremental system capacity).

- New Wind and Transmission
  - The Aeolus-to-Bridger/Anticline transmission line enables interconnection of new low-cost, high capacity factor wind in eastern Wyoming.
  - 1,150 MW of new wind selected through a competitive bidding process, initiated after filing the 2017 IRP (950 MW owned and 200 MW as power-purchase agreements).
  - By achieving commercial operation by the end of 2020, the new wind projects will qualify for production tax credits (100%).
  - Present-value customer net benefits, inclusive of the cost of the new transmission line, are conservatively estimated at $174 million (assuming no value for renewable energy credits, expected O&M cost savings, conservative transfer capability assumptions).

Pacific Gas and Electric Company

2018 Integrated Resource Plan

Kurt Hansen

Director, Portfolio and Resource Forecasting

August 07, 2018

Together, Building
a Better California

PG&E’s 2018 IRP – Objectives

- PG&E’s 2018 IRP meets the CPUC’s plan requirements and focuses on the three key objectives:

  1. *Clean Energy:* For decades PG&E has been a leader in delivering clean energy in California. PG&E’s IRP continues this tradition by meeting California’s ambitious GHG and RPS goals

  2. *Reliability:* Maintaining system reliability is critical, especially as California transitions towards higher levels of GHG-free generation resources. PG&E’s IRP meets CPUC system and local RA requirements

  3. *Affordability:* PG&E’s IRP selects resources to meet California’s clean energy and reliability goals in a least cost manner

Overview of PG&E's 2018 IRP

- PG&E modeled three scenarios:
    1. Conforming
    2. Preferred
    3. Alternative

- Preferred and Alternative scenarios include:
    - Additional transportation electrification - five million EV statewide by 2030
    - Higher CCA load shift
    - Other load modifiers developed by PG&E

- In both the Conforming and Preferred scenarios, PG&E meets its GHG planning target with its existing GHG-free resource portfolio and resources added to comply with existing mandates

- The Alternative scenario examines the impact of the Joint IOUs' Green Allocation Mechanism and Portfolio Monetization Mechanism (GAM/PMM) proposal on PG&E's resource portfolio
    - Alternative scenario shows that if GAM/PMM were adopted, PG&E's need for GHG-free resources would significantly increase, and PG&E would have a near-term procurement need for additional renewable resources

PG&E's 2018 IRP Scenarios

Scenario	Key Changes vs. Conforming Scenario	PG&E Bundled Service Load (2030)	PG&E GHG Emissions Benchmark (2030)	Departed Load Cost Recovery Mechanism
Conforming	n/a	34,187 GWh	6.07 MMT	PCIA with updated market price benchmark[a]
Preferred	• Increase CA electric vehicles in 2030 from 3.3 to 5.0 million (from 1.3 to 2.0 million in PG&E's service territory) • Additional CCA load shift • Higher energy efficiency to meet SB350 • Lower distributed PV generation reflecting updated capacity factor and lower non-PV DG reflecting policy constraints for new fossil based technologies	33,784 GWh	5.50 MMT[b]	PCIA with updated market price benchmark[a]
Alternative	• Same load changes as Preferred • PG&E's bundled RPS and GHG-free large hydroelectric portfolio is reduced via GAM-based allocation to other LSEs • RA reductions via GAM allocation and PMM auctions	33,784 GWh	5.50 MMT[b]	GAM/PMM

[a] Market price benchmarks based on inputs tied to market price forecasts, rather than administratively determined values
[b] PG&E adjusted its GHG emissions benchmark for Preferred and Alternative scenarios reflecting a decrease in PG&E's share of system sales

Conforming Scenario Results

- **No new incremental resource additions beyond currently mandated or authorized procurement**

Technology	Capacity Additions to meet Mandates by 2030 (MW)
Biogas/Biomass	159
Wind	22
Solar	630
Storage*	742
Total	**1,553**

* does not include storage to meet AB2868/Dist. connected

- 2030 CNS GHG emissions of 4.72 MMT (below PG&E's GHG emissions benchmark of 6.07 MMT)
- RPS compliance met through physical deliveries and RPS bank usage
- Sufficient System RA through 2025; RA need starting in 2026 - met by market purchases from existing resources

Preferred Scenario Results

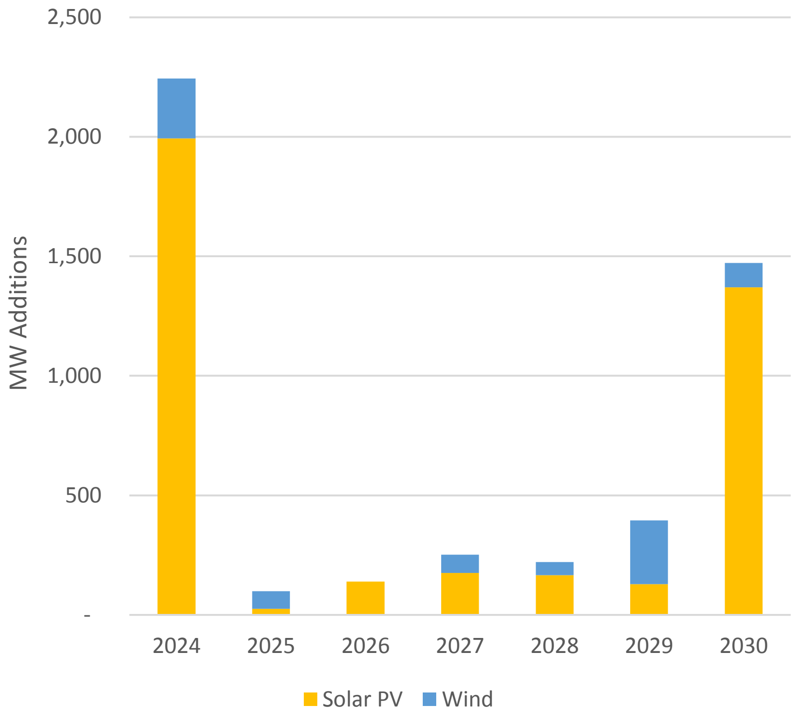
- Although the Bundled portfolio load components in Preferred Scenario are different from Conforming Scenario, PG&E Bundled sales are very similar for the two scenarios
- Since the bundled sales and the assumed cost recovery mechanism in Preferred and Conforming Scenarios are similar, the results are also similar
- No new incremental resource additions beyond currently mandated or authorized procurement
  - Same resource additions as the Conforming Scenario – 1,553 MW by 2030 to meet current mandates*
- 2030 CNS GHG emissions of 4.59 MMT (below the PG&E's GHG emissions benchmark of 5.50 MMT)
- RPS compliance met through physical deliveries and RPS bank usage
- Sufficient System RA through 2026; RA need starting in 2027 - met by market purchases from existing resources

* does not include storage to meet AB2868/Dist. connected

Alternative Scenario Results

Sensitivity to Examine Impacts of Joint IOUs' GAM/PMM Proposal

Incremental Supply-Side Bundled Portfolio Resources Additions[(a)]



- **Approximately 4,800 MW of incremental resource additions beyond Conforming/Preferred scenarios**
- 2030 CNS GHG emissions of 5.50 MMT (PG&E's GHG emissions benchmark of 5.50 MMT)
- REC bank used for RPS compliance through 2023 – additional renewable deliveries needed in 2024
- System RA need starting in 2019 - met by market purchases from existing resources

(a) Incremental resources in addition to existing and planned resources in PG&E's Preferred Scenario

Action Plan & Minimizing Air Pollution

ACTION PLAN

- PG&E will continue to procure RPS resources and energy storage based on existing compliance obligations

- PG&E will continue to offer a suite of demand-side management programs and tariffs for EE, DG, and DR, as well as offer programs for customers located in DACs

- Facilitating the growth of clean transportation technologies is a cornerstone of PG&E's strategy to support California's GHG reduction goals:
  - Growing the charging infrastructure
  - Offering EV-specific rates and
  - Offering customers clean fuel rebates

LOCAL AIR POLLUTANT MINIMIZATION

- PG&E's Oakland Clean Energy Initiative (OCEI) is anticipated to meet a local reliability need while reducing emissions in the Oakland area

- PG&E supports a comprehensive, multi-sector approach to addressing air quality issues

Recommendations for Future IRPs

- Further Inter-Agency Alignment, especially around setting GHG targets, GHG accounting and ensuring reliability
  - Agencies should improve coordination on electric sector GHG planning targets and inter-sector crediting
  - Agencies should ensure implementation of GHG planning targets does not create disincentives to transportation electrification
  - Efforts to consider economic retirements should be coordinated between the CPUC's IRP proceeding, the CPUC's RA proceeding and the CAISO's Transmission Planning Process
- Future IRP cycles should:
  - Incorporate DERs as candidate resources to ensure a truly optimal, least-cost approach to meeting the state's clean energy goals
  - Improve alignment for inputs used by CPUC for the Reference System Plan and by LSEs for their plan development
  - Establish a standardized framework to evaluate air pollutant emissions

Integrated Resource Plan Overview

CPUC IRP Workshop

August 7, 2018

Overview

Well positioned to meet GHG Planning Benchmark

- Clean Net Short calculation shows no need for additional procurement until approximately 2026
- Current RPS Deliveries = around 45% (exceeds 29% target)
- Continued clean energy programs

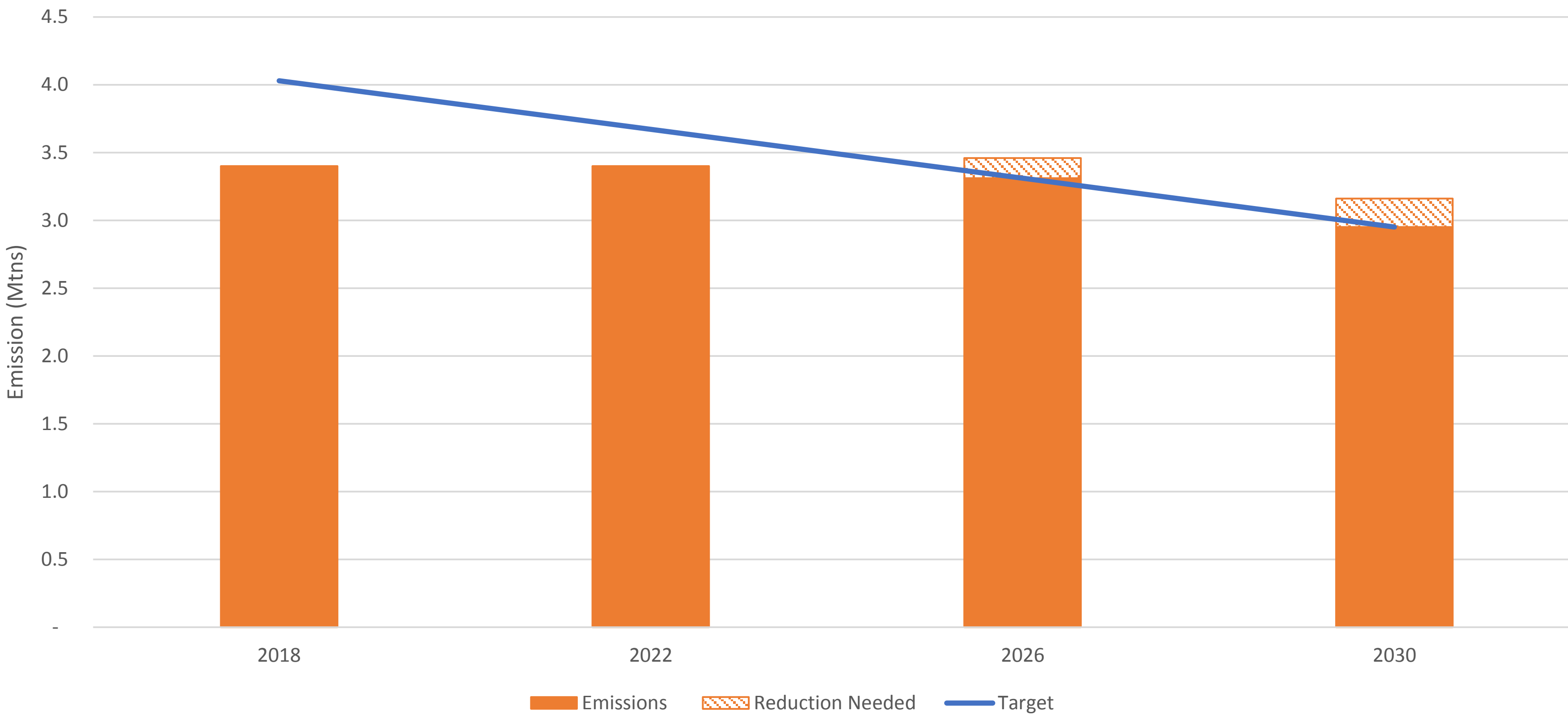
Focused on DACs

- Very few power plants in DACs
- Existing programs target economic assistance and transportation pollution

Initial IRP is a solid proof of concept

- Future rounds should improve on how to address departing load and market uncertainty, optimization of distributed resources, and coordination with other proceedings

Conforming Portfolio - GHG Outlook



Note: although the CPUC established a GHG target for 2030 only, the blue line above extrapolates that target over the planning period in order to provide an estimated trajectory.

Conforming Portfolio – Resource Types

Conforming Portfolio Total Capacity by Resource Type in 2030

Resource Type	Total Installed (MW)	Percent of Total Installed (%)
Natural Gas	3,311	37
Renewables – Supply side	2,870	33
Renewable – Behind the Meter	1,578	18
Incremental Energy Efficiency[1]	780	9
Storage	290	3
Demand Response	31	0
CHP	1	0

[1] Includes incremental EE only.

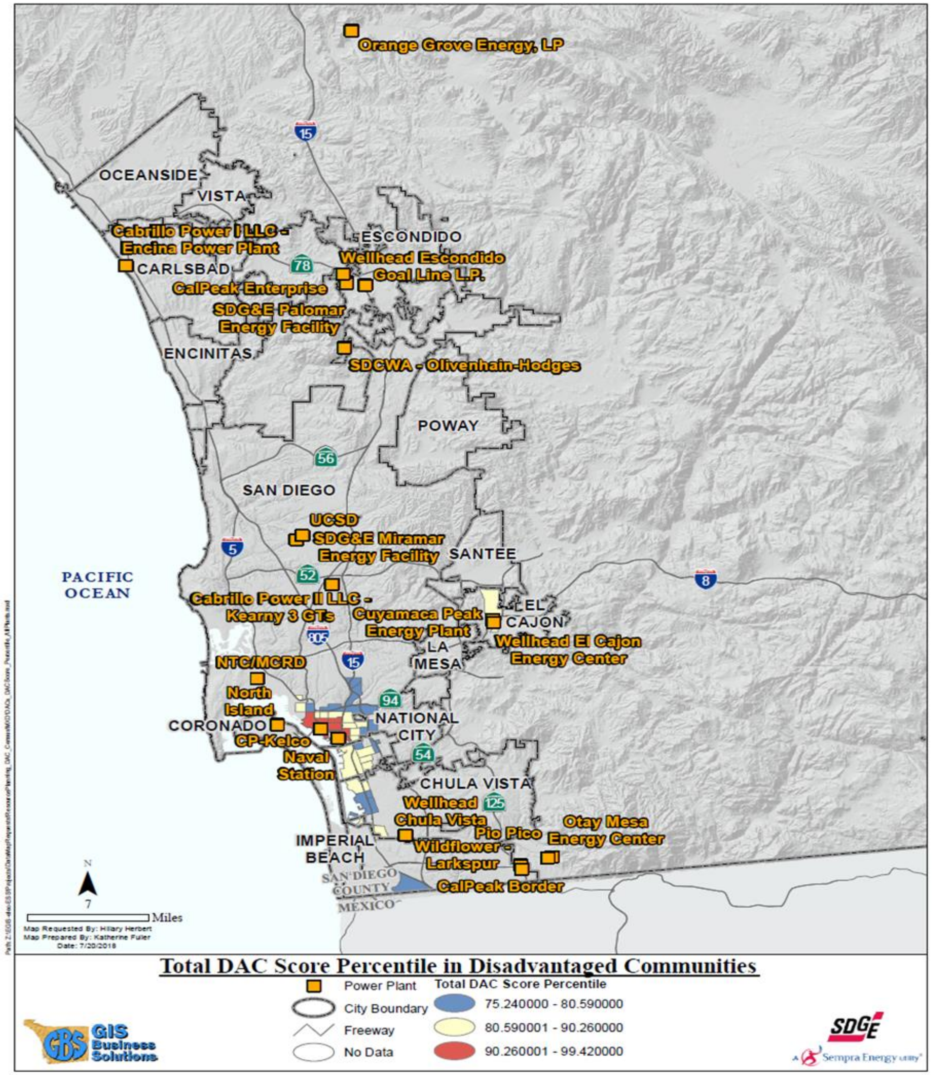
New (Incremental to 2017) Capacity Resources in 2030

Resource Type	Total Incremental Installed (MW)	Percent of Total Incremental Installed (%)
Renewable – Behind the Meter	885	44
Incremental Energy Efficiency	780	39
Renewables – Supply side	195	10
Storage	144	7

Continued Procurement Programs

PROGRAM	SDG&E TARGET (MW)
Conventional	
Combined Heat & Power Feed-in Tariff (Assembly Bill (AB) 1613)	N/A – must-take program for facilities up to 20 MW in size
Combined Heat & Power Settlement (D.10-12-035)	211
Energy Efficiency	
Program Target/Authorization	44 (2018 goal)
Reliability	
Energy Storage (AB 2868)	166 authorized
Resource Adequacy (AB 380)	Local, System and Flexible RA requirements vary by month as determined by the Commission and by the CAISO for the San Diego LCR sub-area
Demand Response Auction Mechanism (R.13-09-011)	$5.5M budget ($1M in 2016, and $1.5M/year for 2017-2019)
Demand Response Programs	33 (2018 target)
Dynamic Rates	26 (2018 target)
Renewable	
Bioenergy Market Adjusting Tariff (Senate Bill (SB) 1122)	25
Green Tariff Shared Renewables Program (SB 43)	59
Qualifying Facility/Public Utility Regulatory Policies Act (Pub.L. 95–617, 92 Stat. 3117)	Must-take program for facilities up to 20 MW in size

Focus on Disadvantaged Communities



SDG&E Owned or Contracted Natural Gas Plants in DACs

Facility	Size MW	Description
CP- Kelco	26.8	CHP Facility, under contract to SDG&E through 2024, per CHP settlement
Naval Station Energy	44	CHP Facility, under contract to SDG&E through 2024, per CHP settlement. New contract converts dispatch from must-take to dispatchable
El Cajon Energy Center	48	Peaking facility under contract till 2035, needed to meet local resource adequacy
Cuyamaca Facility	45	Peaking facility owned by SDG&E, needed to meet local resource adequacy
El Cajon Storage facility	7.5	New storage facility added in 2017

SDG&E
A Sempra Energy utility®

Lessons Learned

The Process Struggles To Deal With Departing Load and Market Uncertainty

- Near term procurement is risky in light of potential for CCA/Retail Choice and questions about reliability procurement obligations.

The Process Does Not Currently Show Whether DERs Are Cheaper Than Supply Side Options

- EE, BTM Solar, DR, and EV estimates are currently baked into the portfolio. Unclear what will happen when the 2019 IRP process attempts to model whether these are the most cost-effective options relative to supply side resources.

Proactive Coordination with Other Proceedings is Needed

- Need to solidify connection between planning and procurement.

Southern California Edison
2017-18 Integrated Resource Plan

California Public Utilities Commission IRP Workshop

August 7, 2018

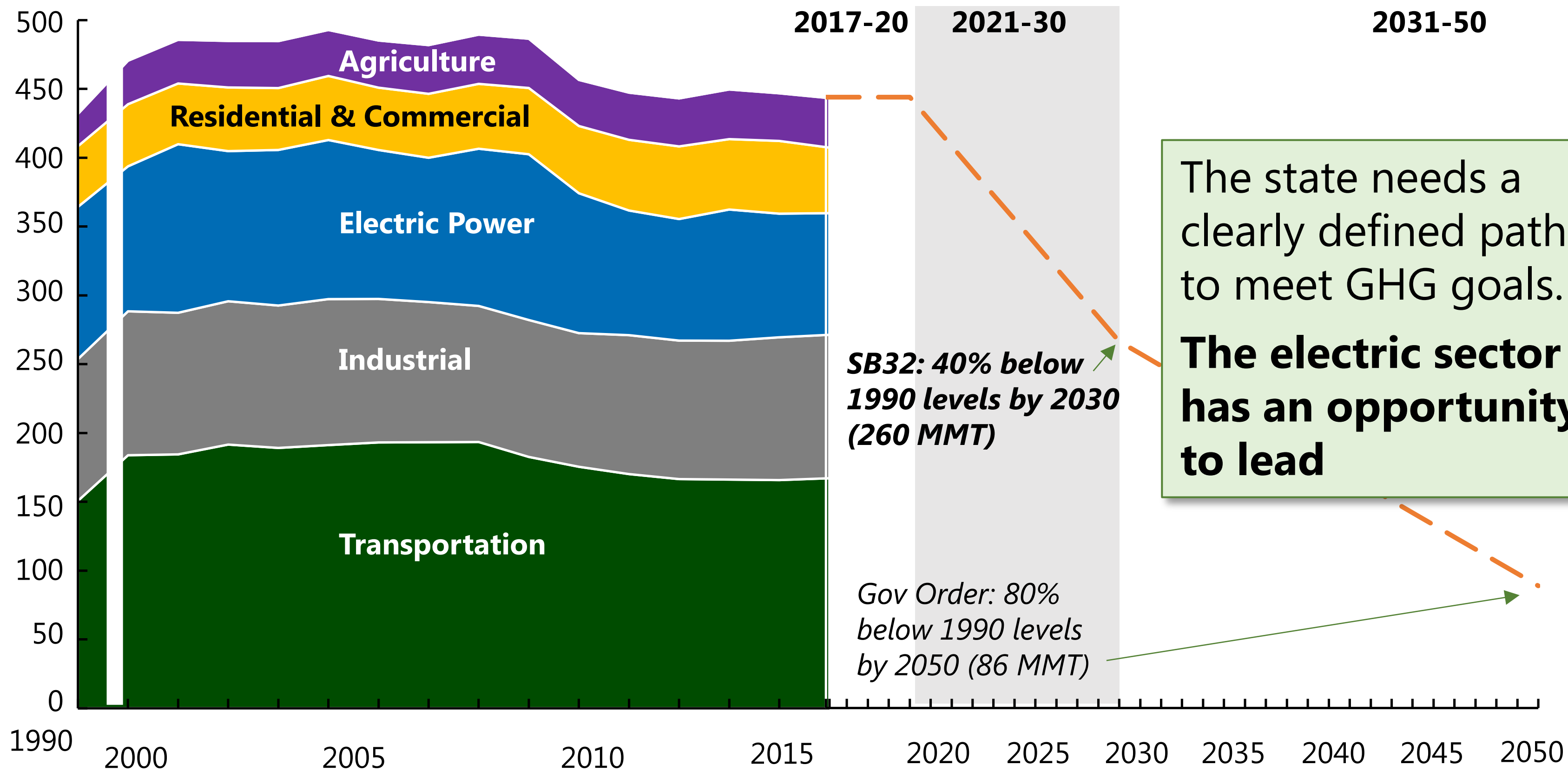
Overview of presentation

I	**SCE's vision for a deeply decarbonized California grid**
II	**SCE's Preferred Portfolio and proposed action plans**
III	**Future of IRP**

Achieving California's GHG goals in 2030 and beyond requires an acceleration of decarbonization

California GHG Emissions

MMT of CO2 equivalent



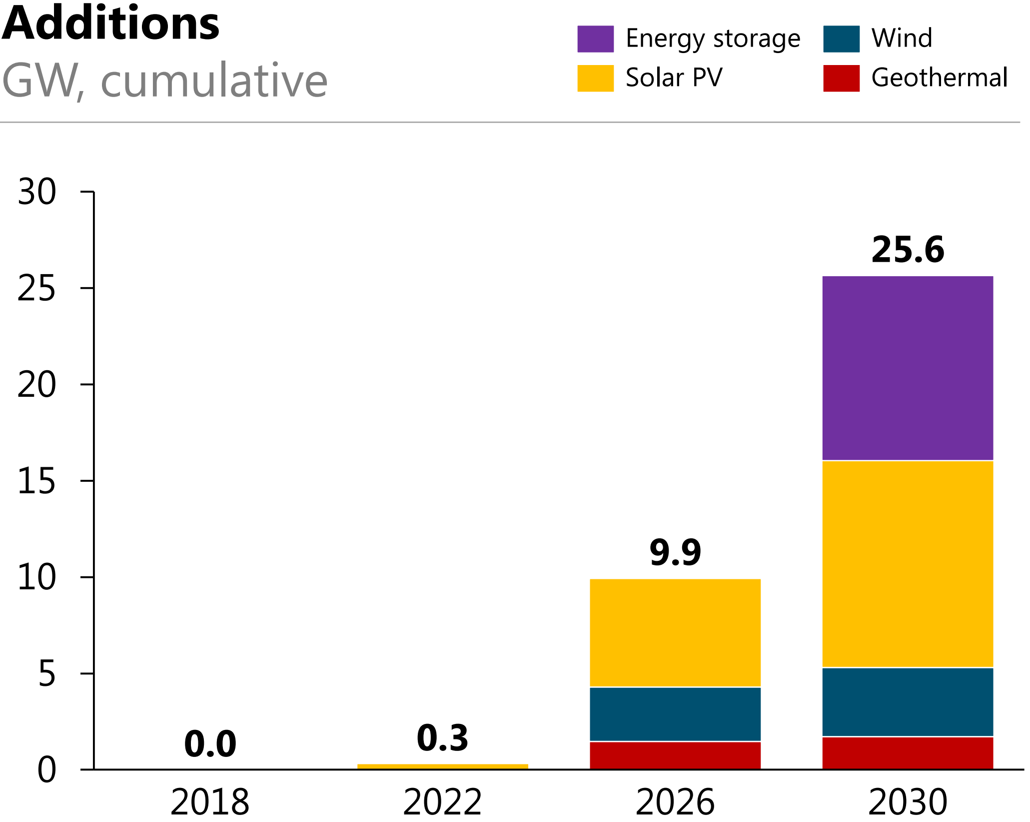
The state needs a clearly defined path to meet GHG goals.

The electric sector has an opportunity to lead

SCE designed a CAISO-wide System Plan that realizes its electric-led decarbonization vision

SCE Pathway System Plan Capacity Additions

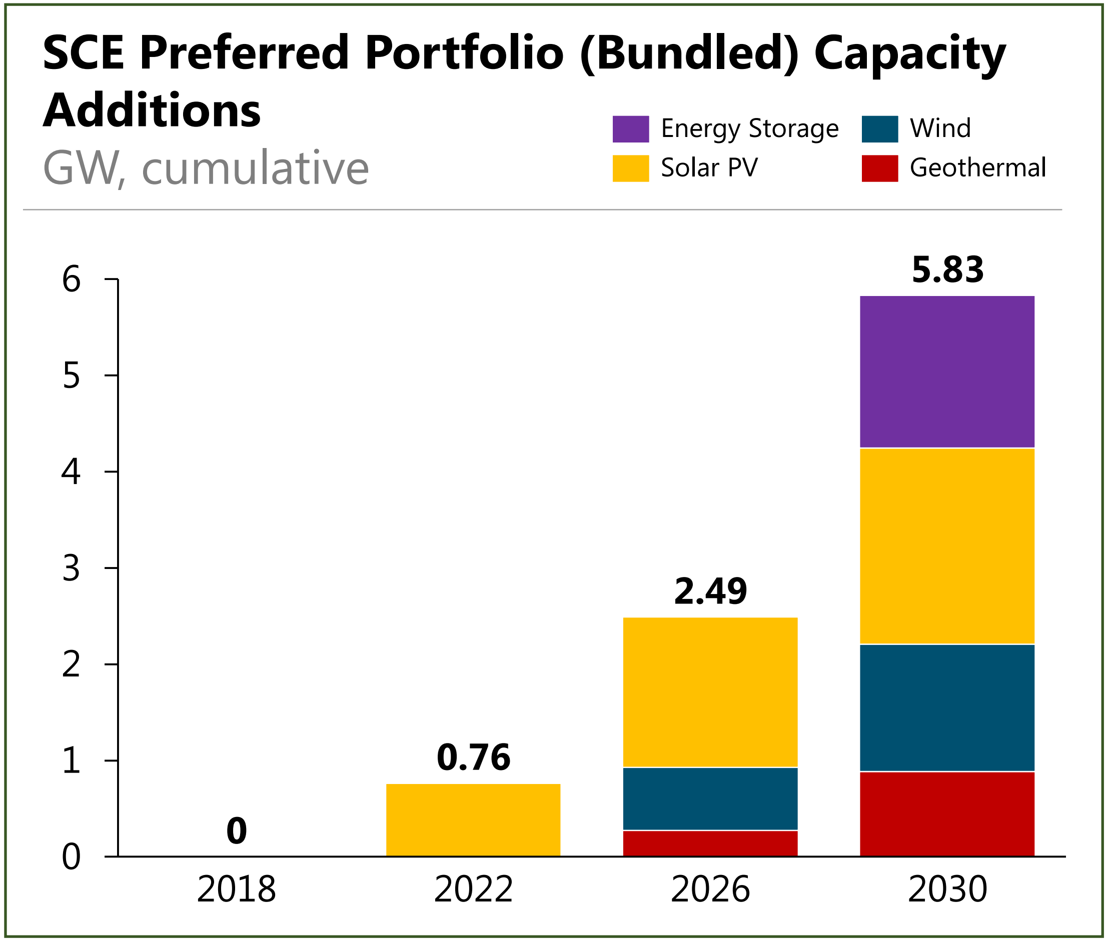
GW, cumulative



Actions to achieve 28 MMT statewide

- Increased electrification load outpaced by reductions from:
  - Energy efficiency
  - BTM PV
- More renewable build
- More energy storage

SCE's Preferred Portfolio achieves its share of this deep decarbonization, high electrification future



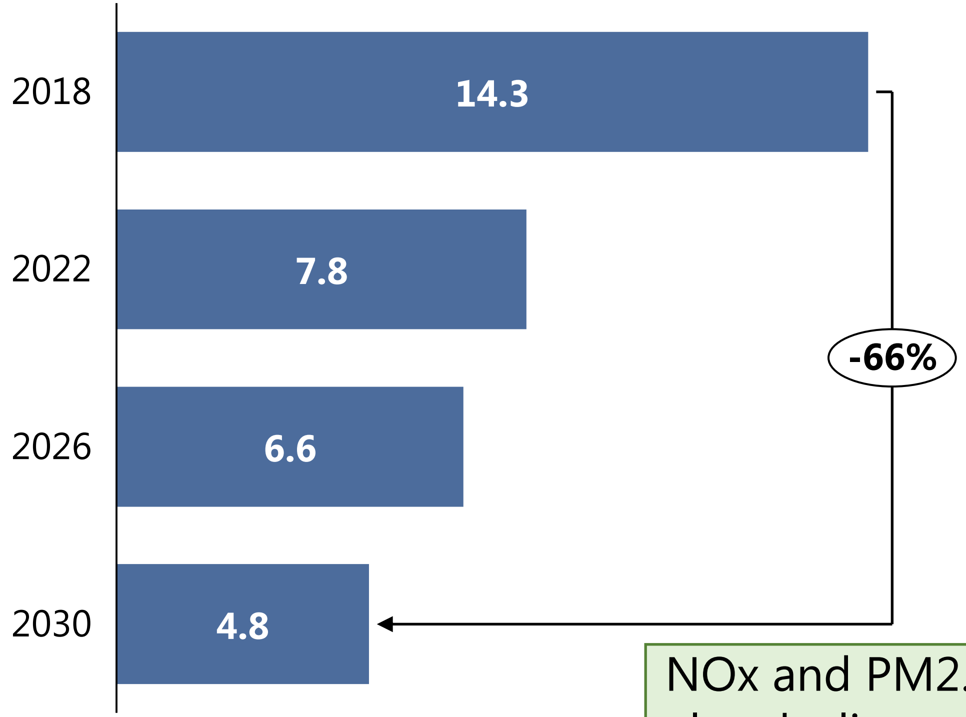
Key conditions

- Equity among LSEs in reaching 28 MMT statewide
- Equitable departing load cost allocation mechanism to replace the PCIA

Note: SCE's Conforming Portfolio indicates no procurement need, under current PCIA methods

SCE's Preferred Portfolio reflects significant emissions reductions

SCE Preferred Portfolio GHG emissions
MMT of CO2e, as modeled



NOx and PM2.5 also decline >50%

Reducing emissions, overall and in DACs

In the portfolio

- No new gas plants
- Significant renewable additions
- Energy storage for integration

Other actions

- Transportation electrification
- Exploring additional EGTs

SCE's Action Plan includes a conditional request for procurement; also addresses reliability issues

Conditional procurement plan	Transmission studies	Reliability thresholds
If Commission adopts **28-30 MMT target** and an **equitable departing load cost allocation mechanism to replace the PCIA**, then SCE's Preferred Portfolio will be actionable	No study of **economic gas retirements**, **transmission needs** in deep decarbonization high electrification case	IRP has not yet addressed **gas deliverability and reliability challenges**, potential **early gas retirements**
Begin procurement process in 2019 to bring online 2.2 GW by 2022-24	**Transmission Planning Process should take up these issues in 2019**	**Authorize "reliability threshold" mechanism for energy storage procurement to meet reliability needs**

In the 2019-2020 cycle, IRP should achieve deeper decarbonization and better process alignment

Deeper decarbonization	Intra- and inter-agency coordination	Fully integrate supply, demand-side resources
▪ Set GHG planning target based on **economy-wide, optimized view** (such as 28-30 MMT) ▪ Study a **high electrification** case	▪ Enact **"umbrella proceeding"** vision outlined in OIR ▪ **Align timing, inputs** with CEC, CAISO, CARB processes	▪ Better integrate **DERs as selectable** resources ▪ Develop **robust CRVM** to appropriately value resources

IRP process observations

Delphine Hou
Manager, State Regulatory Affairs

IRP Workshop on LSE Plans - Non-LSE Stakeholder Panel Discussion, California Public Utilities Commission

August 7, 2018

Process issues

- The CAISO has identified two process issues to be addressed:
  1. Opportunity for modeling parties to provide meaningful feedback; and
  2. Articulation of process for aggregating LSE plans.

Issue 1: Provide meaningful feedback – Original plan

Guide to Production Cost Modeling in the Integrated Resource Plan Proceeding (Attachment B to February 8, 2018 ruling)

(1) Staff calibrate RESOLVE and SERVM model input data with Reference System Plan and 2017 IEPR demand forecast

(2) Staff posts SERVM model input data and documentation

(3) Staff hosts monthly Modeling Advisory Group meetings

(4) Staff and modeling parties conduct modeling based on (2)

(5) Staff and modeling parties share results and revise as needed

(6) Parties formally comment

(7) Commission provides revised guidance

Issue 1: Provide meaningful feedback – Prelim results presentation

- *IRP Modeling Advisory Group Meeting Production Cost Modeling with the Reference System Plan and the 2017 IEPR: Preliminary SERVM model results*, July 13, Page 50

Modeling Activity Estimated Completion

TASK	Estimated Completion Date
Post final Unified RA/IRP Inputs and Assumptions describing revised SERVM inputs and configuration – including workbooks	End of July
Finish calibrated loss of load and ELCC studies, and reserve margin calculations	End of July
Present results of above at August MAG meeting	August 10
Complete draft report for ruling seeking comment	Late August
Complete final report for ruling with any revised PCM guidelines	Late September
Post aggregated LSE portfolio datasets for PCM	Late September
Complete SERVM studies with aggregated LSE portfolios	Late November

Issue 1: Provide meaningful feedback – MAG schedule

- MAG meetings (as of 8/2/18)

Track	May 30, 2018 10am – 12pm Webinar https://join.freeconferencecall.com/cpuc_irp	June 29, 2018 (Fri) 10am – 12pm Webinar https://join.freeconferencecall.com/cpuc_irp	July 13, 2018 (Fri) 10am – 12pm Webinar https://join.freeconferencecall.com/cpuc_irp	August 10, 2018 (Fri) 10am – 11am Webinar https://join.freeconferencecall.com/cpuc_irp	Sept. 28, 2018 (Fri) 10am – 12pm Webinar https://join.freeconferencecall.com/cpuc_irp	October 29, 2018 (Mon) 10am – 4pm In-Person Meeting Courtyard Room @ 505 Van Ness, SF	November 29, 2018 10am – 12pm Webinar https://join.freeconferencecall.com/cpuc_irp	December 2018 No Meeting
IRP 2017-18			• "As found" results (SERVM) • Lessons learned	• GHG Accounting Discrepancies between CAISO 2017 and RESOLVE 2018	• Aggregated LSE filings results		• "As found" results • ELCC and PRM results • Recommendations for Preferred System Plan	
IRP 2019	• Method for Considering Locational Values in IRP • BTM and MUA Storage Sources and Method Options	• Method for Calculating DRP Locational Value Inputs for use in IRP				• LCR assumptions • Staff to answer clarifying questions on ruling on inputs and assumptions	• Proposed LCR Inputs to RESOLVE	
IRP 2021						• Present evaluation of different capacity expansion modeling platforms: Aurora, RESOLVE, SERVM, and other.		

Issue 1: Provide meaningful feedback – next steps?

Guide to Production Cost Modeling in the Integrated Resource Plan Proceeding (Attachment B to February 8, 2018 ruling)

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(2) Staff posts SERVM model input data and documentation

(3) Staff hosts monthly Modeling Advisory Group meetings

(4) Staff and modeling parties conduct modeling based on (2)

(5) Staff and modeling parties share results and revise as needed

When?

(6) Parties formally comment Next opportunity 9/12?

(7) Commission provides revised guidance

Issue 2: Process for aggregating LSE plans – Original plan

- *Guide to Production Cost Modeling in the Integrated Resource Plan Proceeding* (Attachment B to February 8, 2018 ruling)

VI. Modeling Steps

A. Aggregate the individual LSE Plans into the Preferred System Plan SERVM dataset
   1. The aggregation process must ensure that no resources are double-counted or under-counted, and that the aggregate of new resources selected by LSEs does not exceed the available resource potential. This step may require staff to make additional data requests to LSEs to resolve any issues.
   2. Staff posts the SERVM model input data representing the Preferred System Plan. This is also a key deliverable from staff to parties and serves as the common input for any party using production cost modeling to conduct their own evaluation of the Preferred System Plan, similar to the function and form of the SERVM model input data that was provided by staff at the beginning of the calibration and vetting process described above.

Issue 2: Process for aggregating LSE plans – Prelim results presentation

- *IRP Modeling Advisory Group Meeting Production Cost Modeling with the Reference System Plan and the 2017 IEPR: Preliminary SERVM model results*, July 13, Page 50

Modeling Activity Estimated Completion

TASK	Estimated Completion Date
Post final Unified RA/IRP Inputs and Assumptions describing revised SERVM inputs and configuration – including workbooks	End of July
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Issue 2: Process for aggregating LSE plans – Prelim results presentation

- Suggestions:
  - Provide guidelines for how CPUC Staff will address aggregation prior to posting aggregated LSE portfolio datasets.
  - Assuming the conforming scenario will be modeled, explain how decisions between modeling different LSE-preferred scenarios will be made.