Summer 2021 Electric Supply

Electric Energy Markets

- Electricity must be generated instantaneously
  - Supply constantly adjusted to match demand
- Reserves & Reserve Margin
  - Electric generation assets over and above forecasted demand
  - Minimize the risks of the loss of generation
  - Reserve Margin: % of reserves above demand
- Reserve Margin **<u>targets</u>** based on calculating risk of certain events:
  - Unexpected increases in customer consumption
  - Unscheduled shutdowns of an electric generation plant or transmission

CALIFORNIA

California has first rolling blackouts in 19 years — and everyone faces blame

While California braced for another round of rolling blackouts Monday night, the state's grid operator held off for a second straight night.

By **DEBRA KAHN** and **COLBY BERMEL** | 08/18/2020 12:19 AM EDT | Updated 08/18/2020 01:24 PM EDT

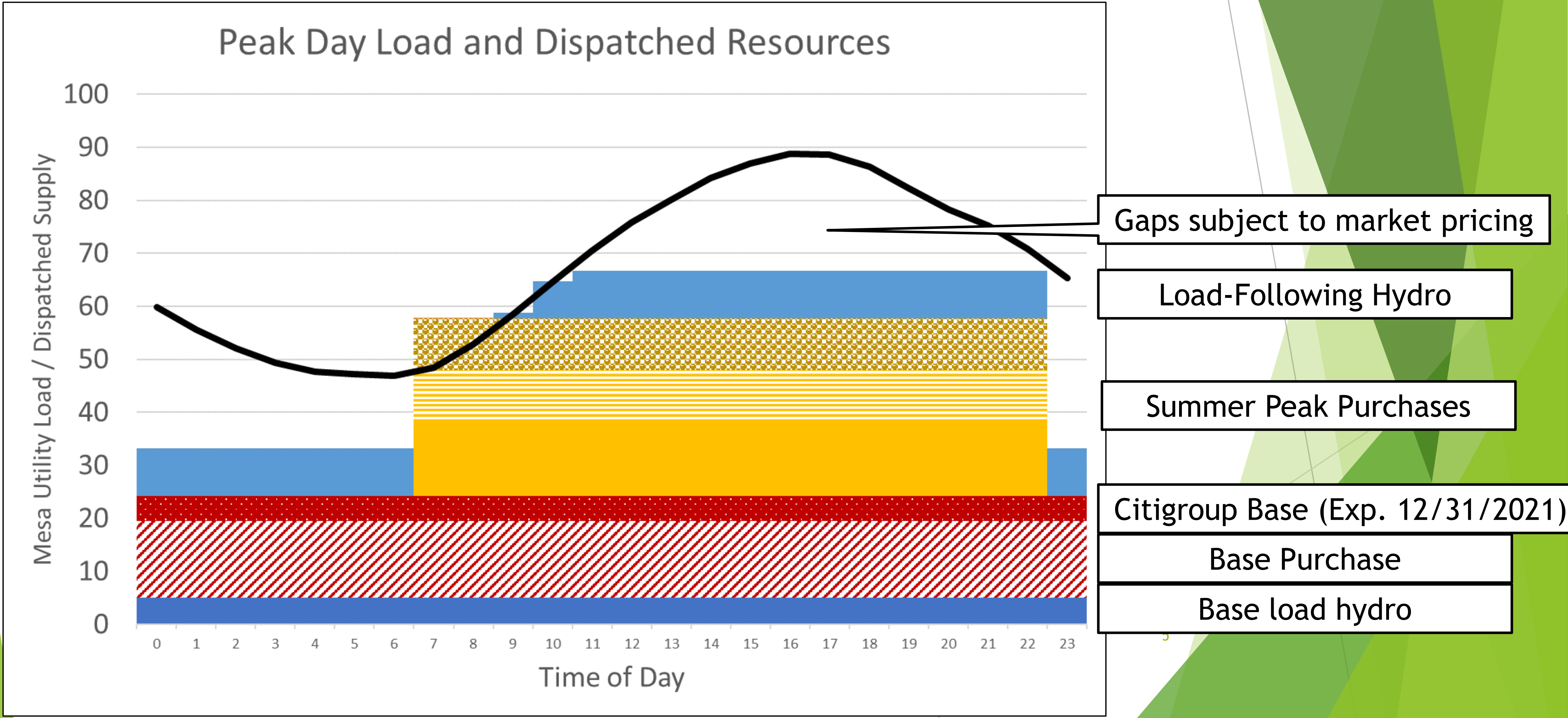
- August 2020 and February 2021 we saw the results of shrinking reserve margins and unexpected shutdowns of generation

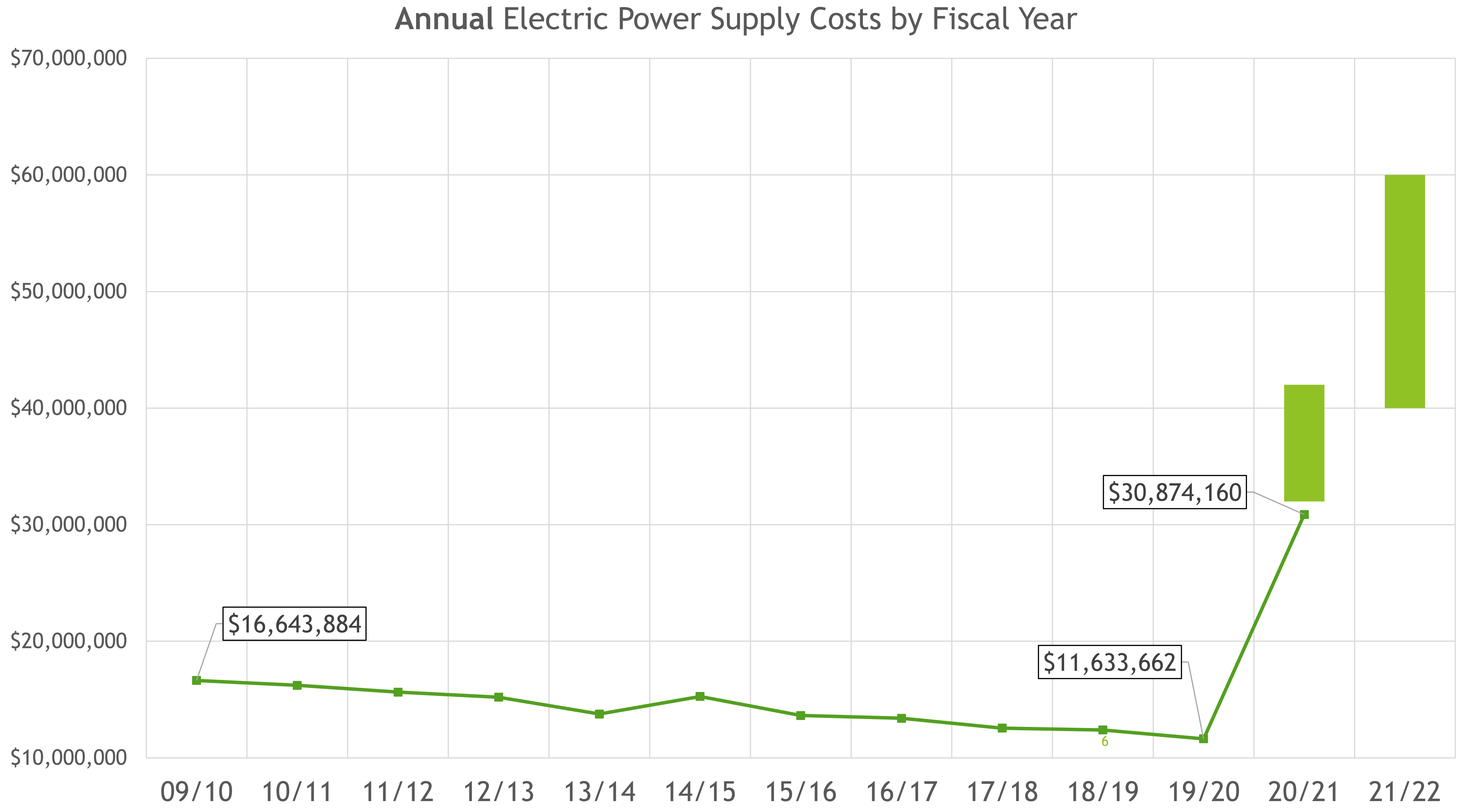
- Western Market experiencing:
  1. Retirement of large generating plants
  2. WITHOUT adequate new plant builds
  3. Fastest customer growth in the country

Reserve Margins & Demand

Summer	California/N. Baja MX Demand	Desert Southwest Demand
2016	54,621 (25.4% reserves)	23,773 (26.5% reserves)
2017	54,774	23,207
2018	54,112	23,883
2019	55,109	24,286
2020	54,214 (17.2% reserves)	24,571 (20.5% reserves)
2021 (Projected)	55,721	25,652
2022 (Projected)	53,451	26,128

Peak Day Load and Supply – Summer 2021





Annual Electric Power Supply Costs by Fiscal Year
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$16,643,884
$11,633,662
$30,874,160
09/10
10/11
11/12
12/13
13/14
14/15
15/16
16/17
17/18
18/19
19/20
20/21
21/22

Mesa's Electric Energy Supply Strategies

- Integrated Resource Planning (IRP) used to plan for electric supplies
- Maintain hydroelectric supplies: 20% hydroelectric power under long-term contracts
- Increase competition for market purchases: 80% wholesale energy procurements
  - 1-5 Year term purchases via competitive RFP
  - Spot market/short term purchases through Western RMS

Resource Type	IRP Plan by 2023	Progress
Utility Scale Solar	20 MW	First 15 MW by 2023
Internal ESA Solar	2 MW	820 kW @ ASU, Plaza, MCP, 55 N
Energy Efficiency/Conserv.	2.3 MW	AMI in progress, plan for federal funding
Customer-Owned Solar	1.2 MW	1 MW
Internal Fast-Ramping Gen.	4.2 MW	3 MW applied for via fed. grant
	29 MW @ Peak	

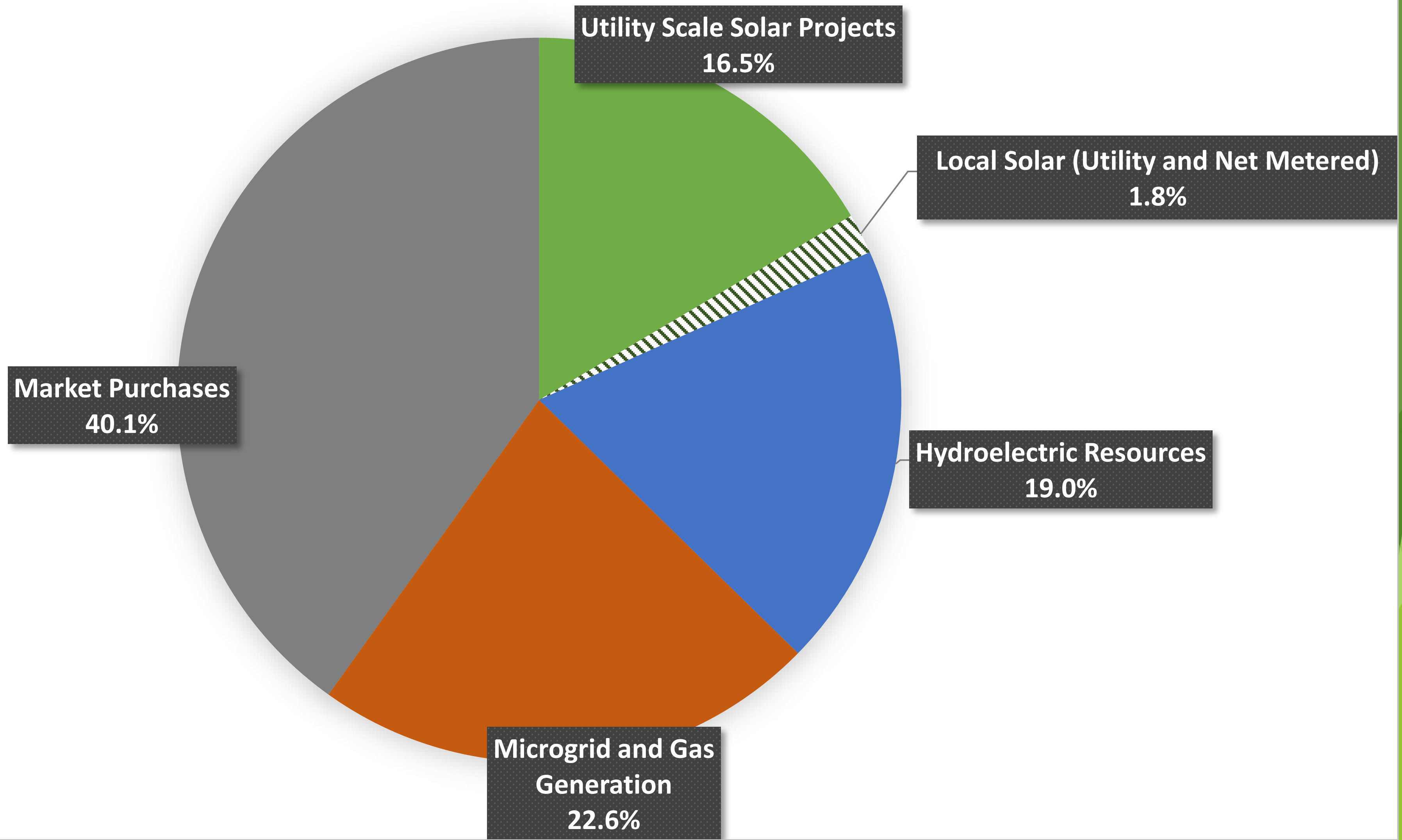
Strategies to Mitigate – Near Term

- Reduce Peak Usage at City Facilities
- Customer messaging
- Customer conservation programs
  - Seeking funding through LIHEAP and Federal Funding
- Summer Energy Assistance Program
- Working with local relief organizations
- Rate Impact Mitigation

Strategies to Mitigate – Mid-Long Term

- **<u>1. Supply Side</u>**
  - **Gas Generation in ESA
  - Utility Scale Solar – 2023-2024
  - Local Solar at City Facilities
  - Microgrids
- **<u>2. Demand Side</u>**
  - City Building Demand Reduction
  - Customer programs
  - AMI/AMR - Rates
  - Customer Net Metering Program

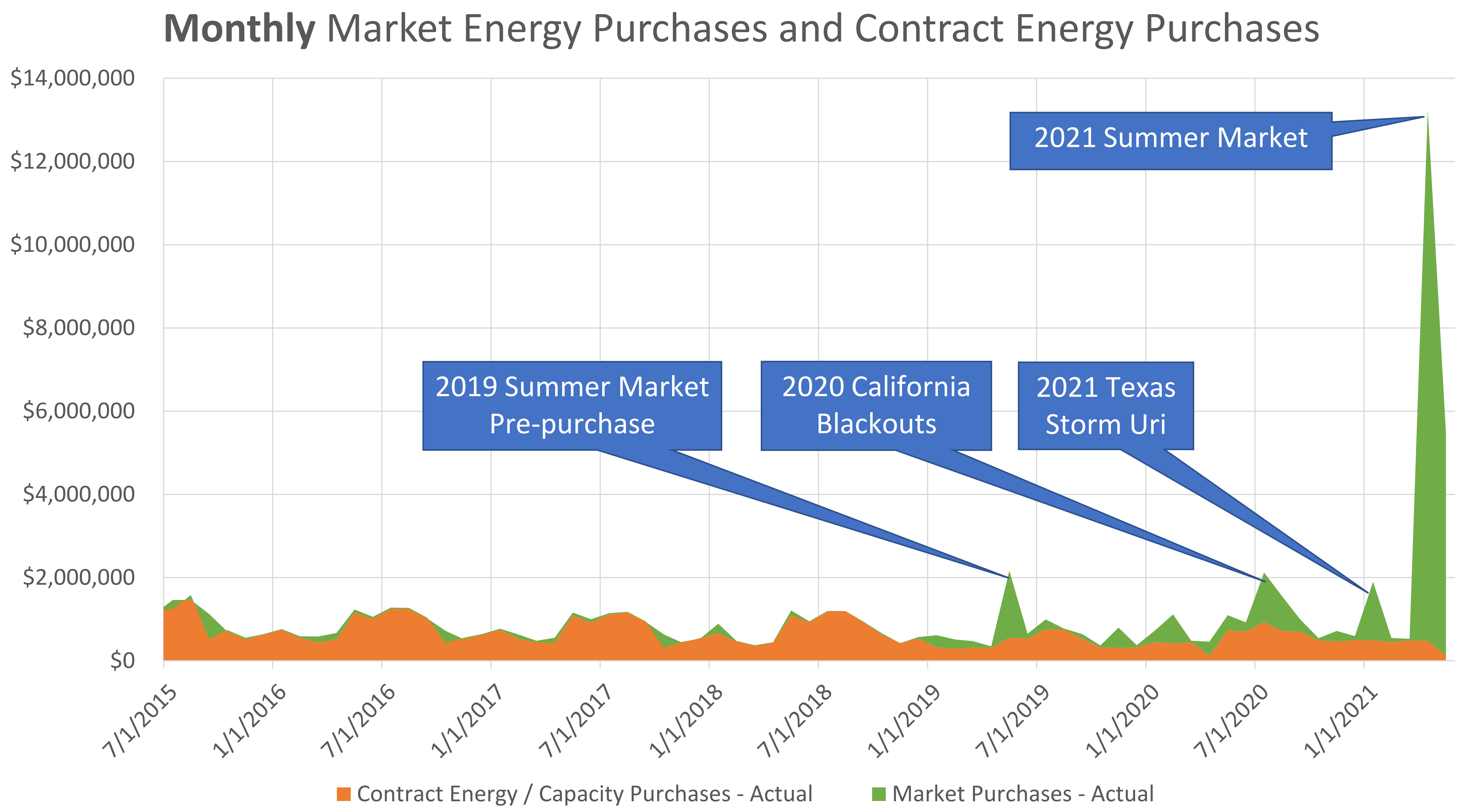
FY23/24 - Power Supply Portfolio by Source with Utility Solar, Public Safety Microgrid, 10 MW Internal Gas Generation



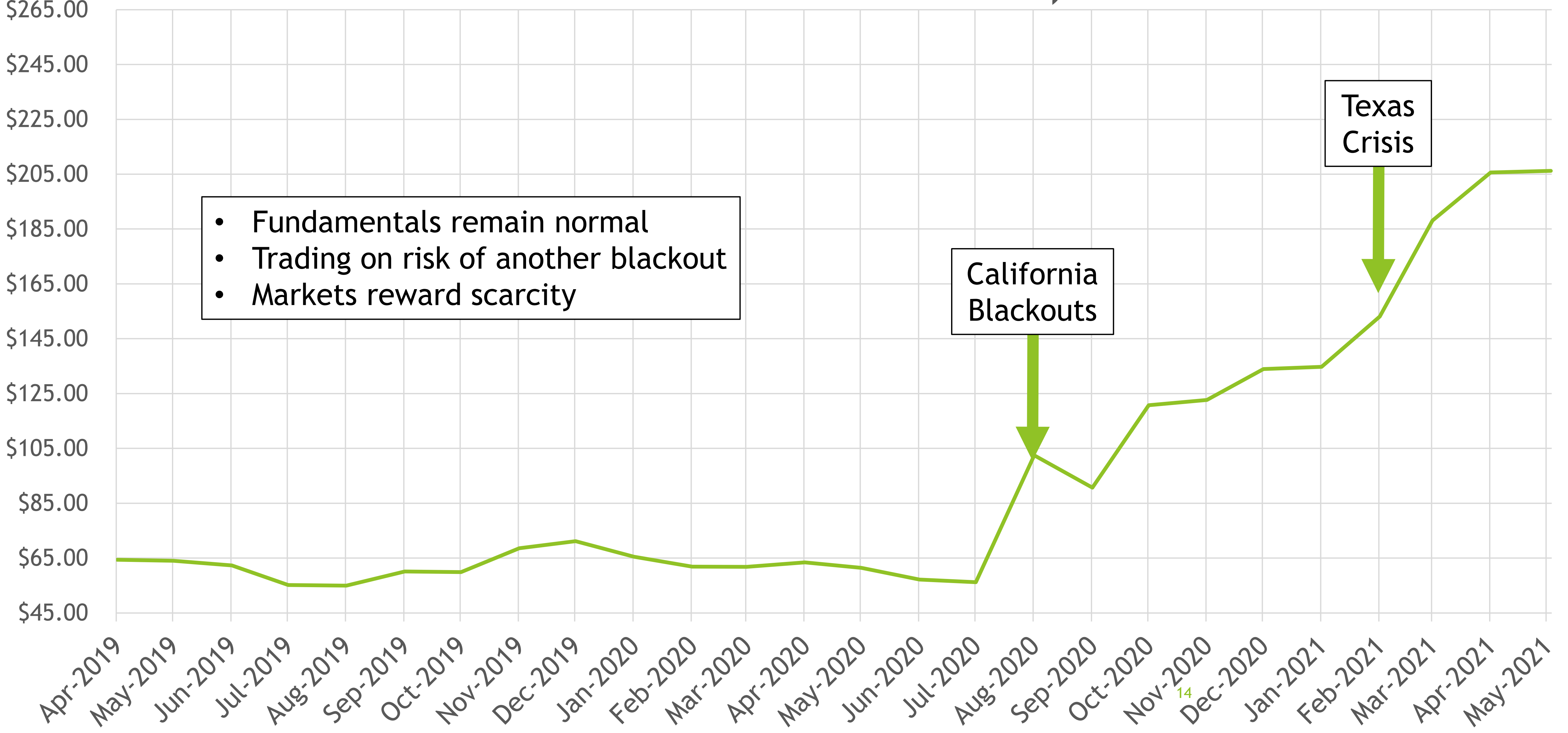
Questions?

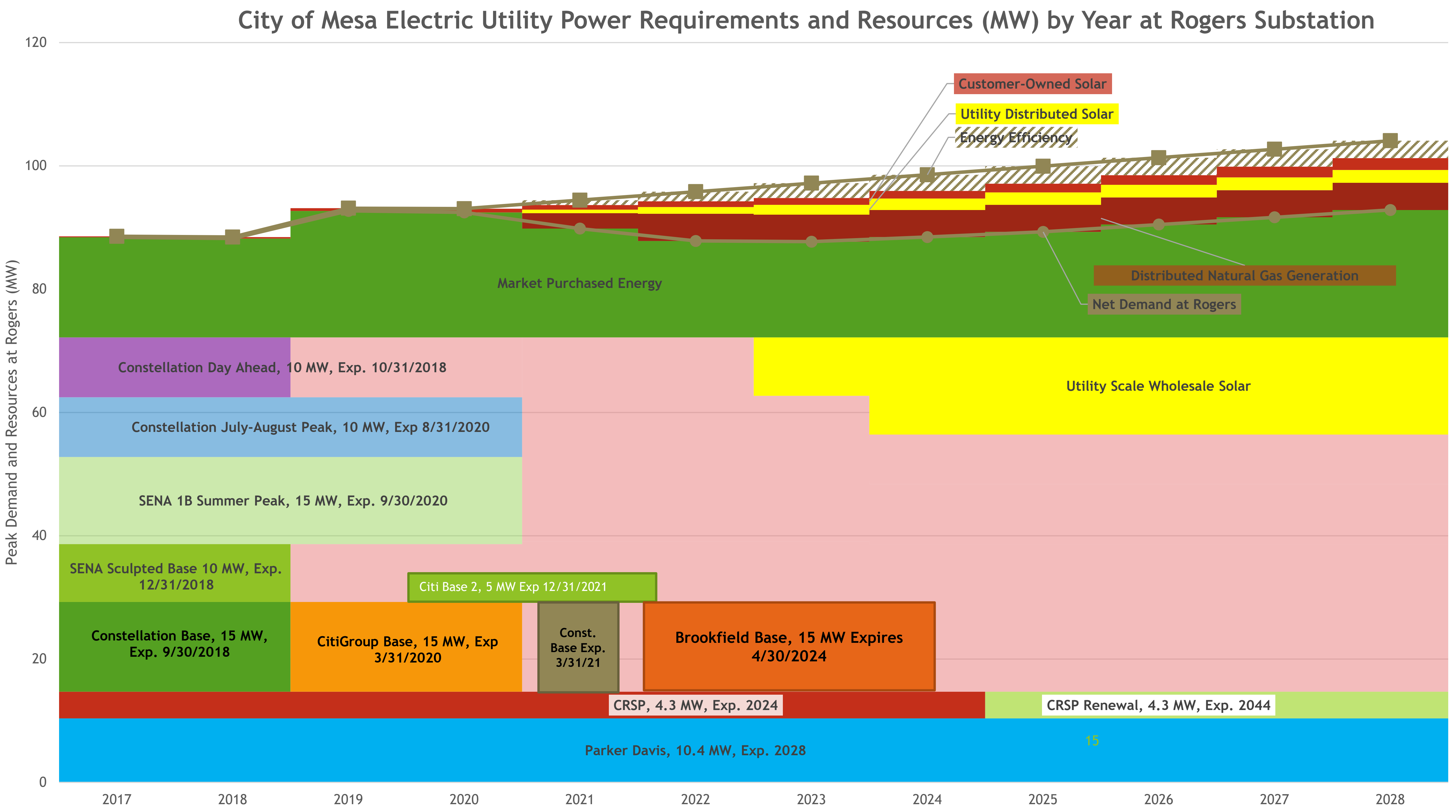
Reserve Margins & Demand

Summer	California/N. Baja MX Reserve Margin	Desert Southwest Reserve Margin
2016	25.4%	26.5%
2017	20.3%	27.7%
2018	19.2%	23.7%
2019	23.3%	30.8%
2020	17.2%	20.5%
2021 (Proj.)	21.4%	18.1%
2022 (Proj.)	27.8%	17.3%

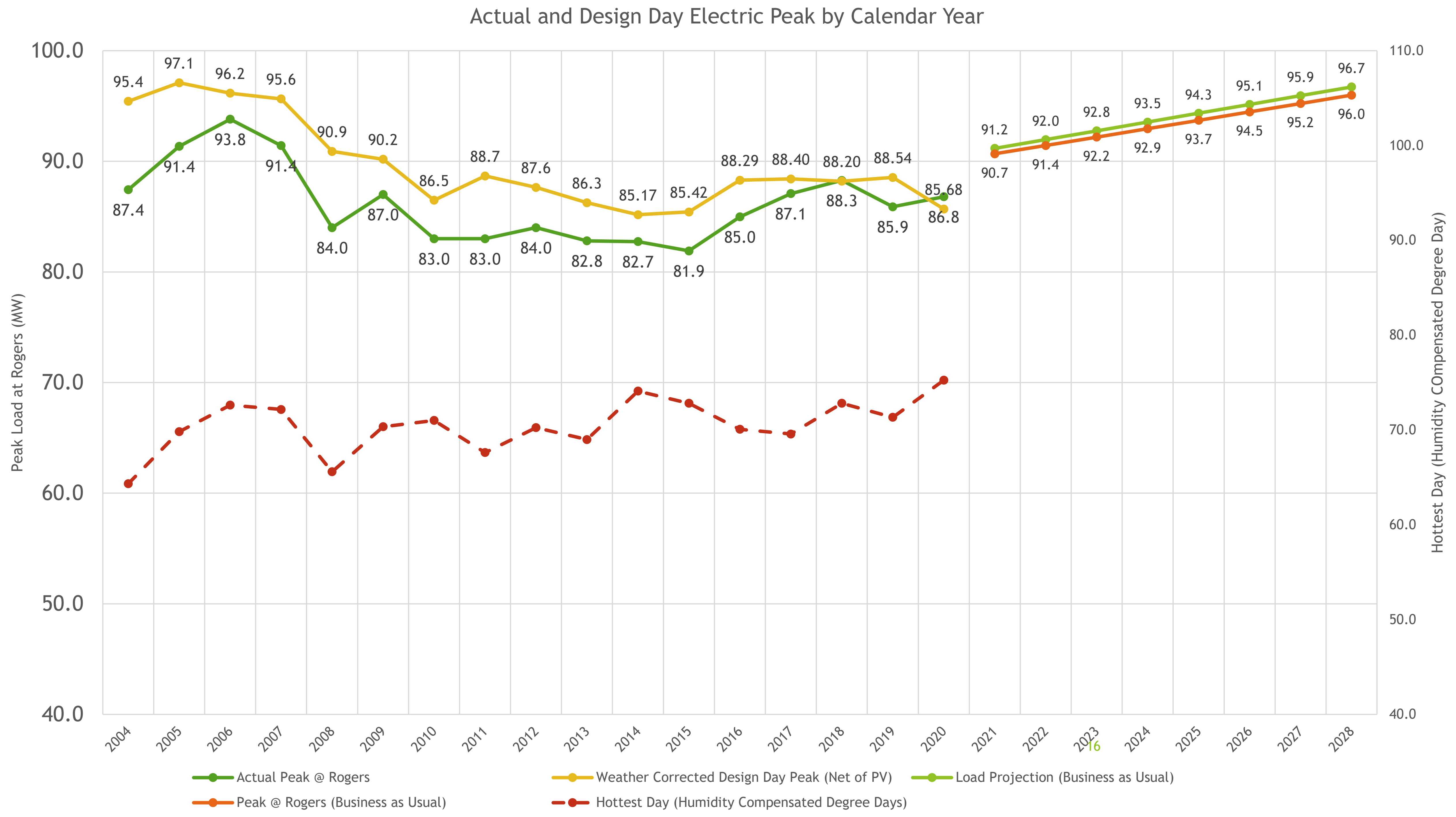

Monthly Market Energy Purchases and Contract Energy Purchases
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
7/1/2015
1/1/2016
7/1/2016
1/1/2017
7/1/2017
1/1/2018
7/1/2018
1/1/2019
7/1/2019
1/1/2020
7/1/2020
1/1/2021
2021 Summer Market
2019 Summer Market Pre-purchase
2020 California Blackouts
2021 Texas Storm Uri
Contract Energy / Capacity Purchases - Actual
Market Purchases - Actual

Summer 2021 Electricity Pricing (by Month Purchased in Advance)





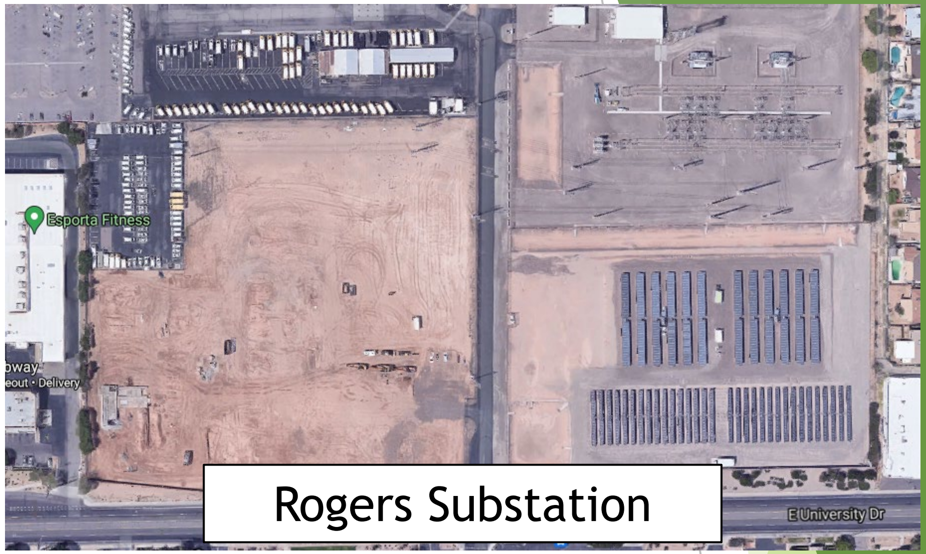
City of Mesa Electric Utility Power Requirements and Resources (MW) by Year at Rogers Substation
Peak Demand and Resources at Rogers (MW)
120
100
80
60
40
20
0
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Customer-Owned Solar
Utility Distributed Solar
Energy Efficiency
Market Purchased Energy
Distributed Natural Gas Generation
Net Demand at Rogers
Constellation Day Ahead, 10 MW, Exp. 10/31/2018
Utility Scale Wholesale Solar
Constellation July-August Peak, 10 MW, Exp 8/31/2020
SENA 1B Summer Peak, 15 MW, Exp. 9/30/2020
SENA Sculpted Base 10 MW, Exp. 12/31/2018
Citi Base 2, 5 MW Exp 12/31/2021
Constellation Base, 15 MW, Exp. 9/30/2018
CitiGroup Base, 15 MW, Exp 3/31/2020
Const. Base Exp. 3/31/21
Brookfield Base, 15 MW Expires 4/30/2024
CRSP, 4.3 MW, Exp. 2024
CRSP Renewal, 4.3 MW, Exp. 2044
Parker Davis, 10.4 MW, Exp. 2028



Actual and Design Day Electric Peak by Calendar Year
Peak Load at Rogers (MW)
Hottest Day (Humidity COmpensated Degree Day)
100.0
90.0
80.0
70.0
60.0
50.0
40.0
110.0
100.0
90.0
80.0
70.0
60.0
50.0
40.0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
95.4
97.1
96.2
95.6
90.9
90.2
86.5
88.7
87.6
86.3
85.17
85.42
88.29
88.40
88.20
88.54
85.68
87.4
91.4
93.8
91.4
84.0
87.0
83.0
83.0
84.0
82.8
82.7
81.9
85.0
87.1
88.3
85.9
86.8
91.2
92.0
92.8
93.5
94.3
95.1
95.9
96.7
90.7
91.4
92.2
92.9
93.7
94.5
95.2
96.0
Actual Peak @ Rogers
Weather Corrected Design Day Peak (Net of PV)
Load Projection (Business as Usual)
Peak @ Rogers (Business as Usual)
Hottest Day (Humidity Compensated Degree Days)

Generation Opportunities

- 3rd Party Consultant Evaluation
- High pressure gas + 69 kV Lines
- Loftin Rental
- Wartsila
- GE Turbine Install
- GE Turbine Rental



Rogers Substation

S Center St Triangle

NERC Long Term Reliability Report (12/2020)

Risk of Outages

Most areas are projecting to have adequate resource capacity to meet annual peak demands. However, measures of energy adequacy from the ERO's probabilistic assessment (ProbA), which accounts for all hours in selected study years of 2022 and 2024, are cause for concern in several areas. The following explains these concerns in detail:

- Nearly all parts of the Western Interconnection (WI), with the exception of Alberta, face heightened loss of load risk. The WECC-CAMX assessment area (primarily Californi… which was a subject of concern when the prior ProbA was co… …ed in 2018, could face periods where resources are insufficie… …a energy needs, potentially resulting in up to 22 hours of … …022. The recent experience

"High risk of loss of load" (i.e. outages) means high risk for suppliers which translates to high prices

Risk to Generators

- Natural-gas-fired generation provides 40% of the aggregate on-peak electricity supply capacity in North America, and 41 GW of that capacity is in late-stage planning for addition over the next 10 years. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages due to both insufficient natural gas infrastructure or alternate fuel delivery and/or disruption to natural gas or alternate fuel deliveries. These risks are most heightened in New England, the desert Southwest, and California, where there is increased reliance on natural gas generation and limited back-up fuel.

Risk of Outages

- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all WI areas over studied years. The CAMX area was the only concern in the 2018 probabilistic assessment, but now all areas except Alberta (AESO) are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event, which saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.

*NERC: North American Electric Reliability Corporation

WECC Growth

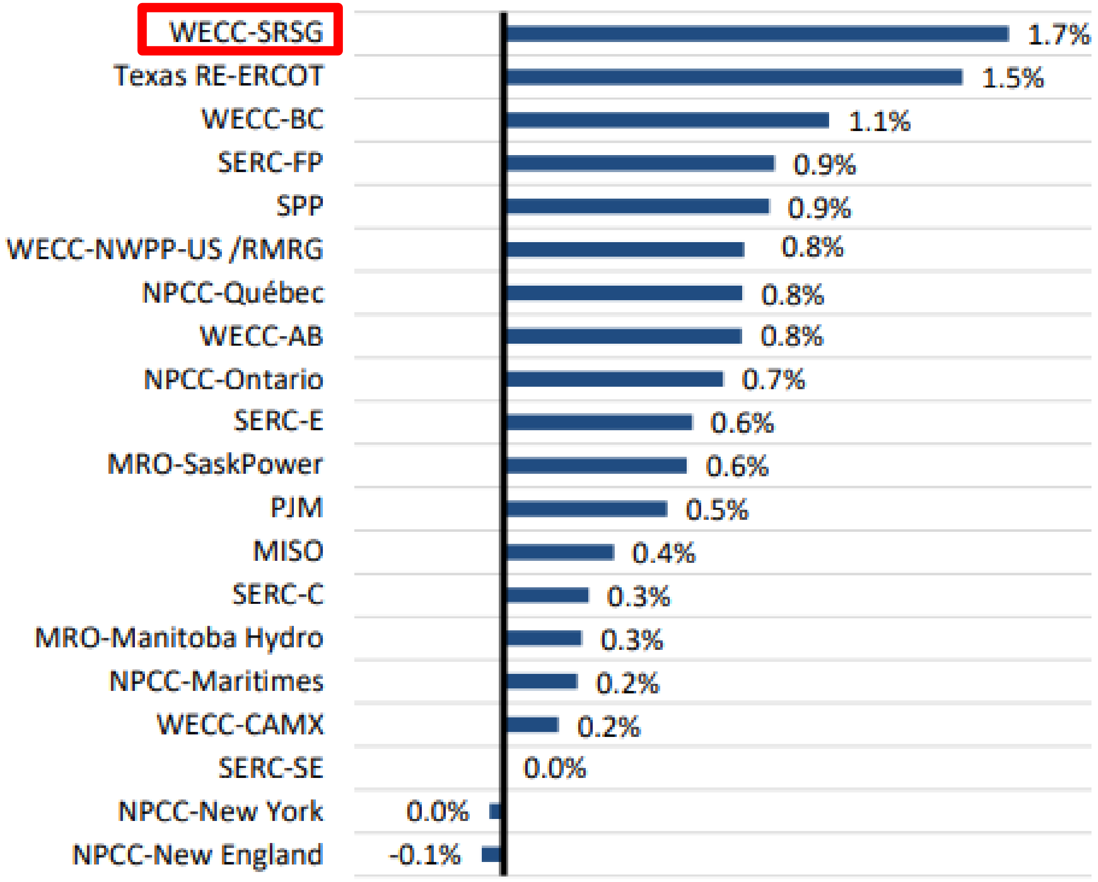


Figure 32: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

- The Desert Southwest is seen as the fastest growing area over the next 10 years; generation must keep pace
- Fast growth without commensurate growth in generation capacity = higher risk of outages due to insufficient generation
- Generation capacity type must meet the resource need (i.e. **<u>Peak Demand time capacity is needed</u>**)

California ISO Demand and Generation

Summer	CAISO Generation Additions (prior to year)	CAISO Generation Retirements	July/August Capacity forecast	1 in 2 peak demand forecast	Actual Peak Demand
2018	692	890	51,947	46,625	46,310
2019	1,523	2,702	51,765	46,511	44,148
2020	3,423	1,991	48,555/46,903	45,907	46,970
2021	3,961	81	50,734/50,010	45,837	

Significant new capacity additions

Almost no retirements

Net capacity increase

Demand continues to decline

CAMX Demand and Generation

Summer	Capacity Forecast (Existing Certain and Net Firm Transfers)	Total Internal Demand
2015	64,102	57,606
2016	66,044	54,621
2017	63,765	54,774
2018	62,658	54,112
2019	64,936	55,109
2020	62,371	54,214
2021	63,569	55,721

Desert Southwest Demand and Generation

Summer (NERC)	Peak Capacity Forecast	Peak Demand Forecast	Hours at Risk
2016	29,289	22,635	
2017	29,094	23,207	
2018	29,061	23,883	
2019	30,445	24,286	
2020	28,693	24,571	
2021	29,672	25,652	
2021 (WECC)	29,300 (24,300 @ 5%)	25,700 (29,100 @ 5%)	415/283

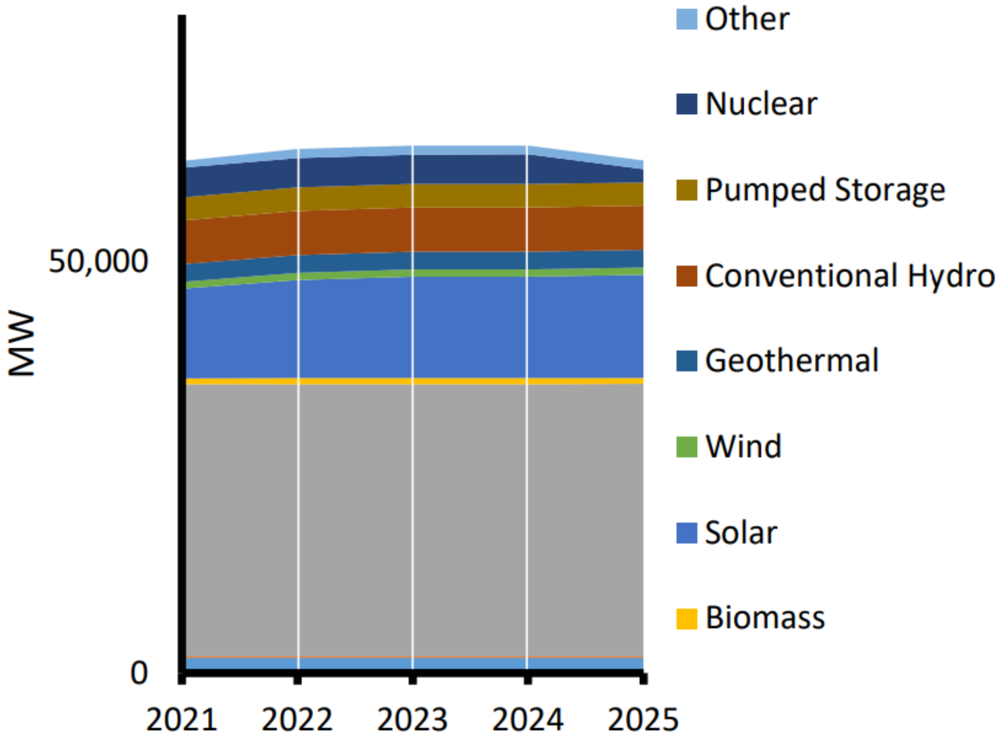
Significant decrease, 2019 to 2020

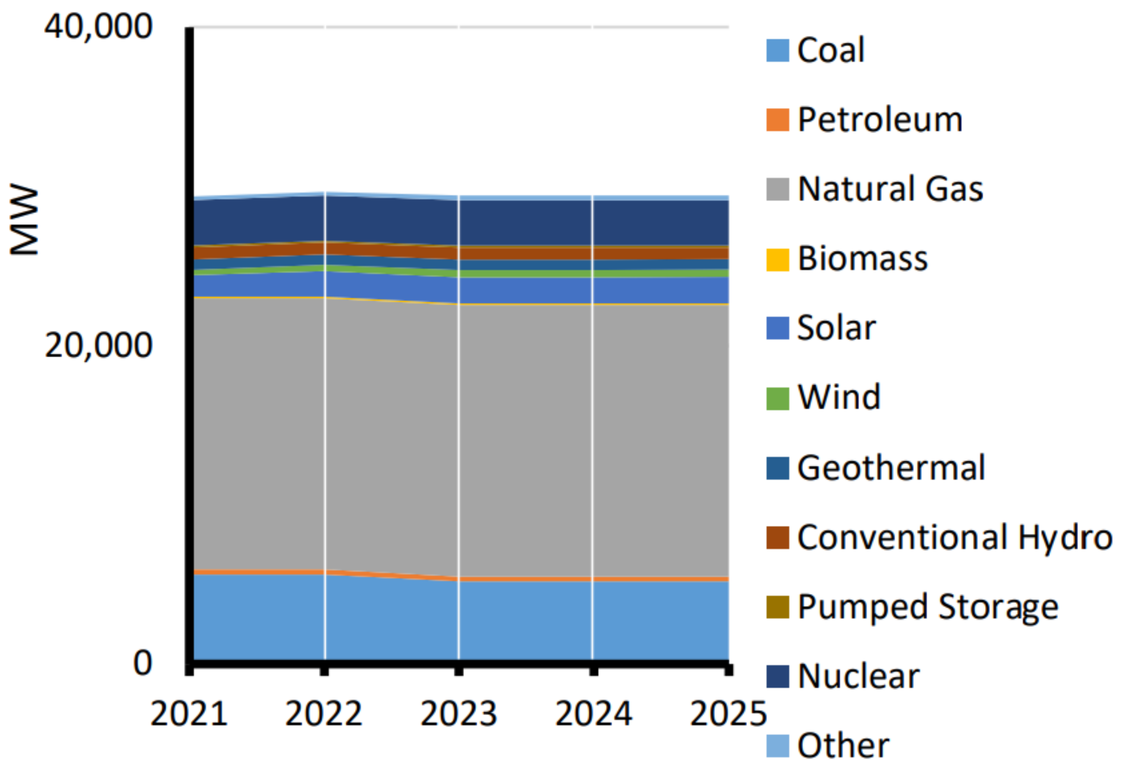
WECC Reserves

Table 9: Planning Reserve Margins (2021–2025)							
Assessment Area	**Reserve Margins (%)**	**2021**	**2022**	**2023**	**2024**	**2025**	
WECC-AB	Anticipated Reserve Margin	22.6%	26.3%	Low 22.8%	24.0%	23.6%	
	Prospective Reserve Margin	32.2%	42.1%	50.5%	55.6%	55.1%	
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%	
WECC-BC	Anticipated Reserve Margin	21.4%	20.6%	Low 19.1%	21.2%	24.1%	
	Prospective Reserve Margin	21.4%	20.6%	19.1%	21.3%	24.2%	
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%	
WECC-CAMX	Anticipated Reserve Margin	21.4%	27.8%	Up 27.3%	26.8%	22.5%	
	Prospective Reserve Margin	21.4%	35.3%	40.8%	41.7%	37.4%	
	Reference Margin Level	18.2%	15.8%	19.1%	19.1%	19.1%	
WECC-NWPP-US and RMRG	Anticipated Reserve Margin	25.9%	24.6%	23.4%	21.6%	20.8%	Down
	Prospective Reserve Margin	25.9%	24.8%	24.0%	22.2%	21.5%	
	Reference Margin Level	15.4%	16.1%	15.2%	15.1%	15.0%	
WECC-SRSG	Anticipated Reserve Margin	18.1%	17.3%	17.0%	14.7%	15.5%	Down
	Prospective Reserve Margin	18.1%	18.1%	19.5%	17.2%	17.9%	
	Reference Margin Level	10.9%	11.9%	11.0%	10.8%	10.7%	

California ISO is the only area with a positive outlook on the reserve margin

Projected Energy Mix – CAMX and SRSG





CURRENT RESOURCE MANAGEMENT PLAN

- Mesa *currently* purchases ~ 80% of its electric energy supplies from the Western Regional Energy Market (Western Market)

- California ISO is Interconnected with the Western Market
  - What happens in California significantly impacts the West
  - If/When California's and Desert Southwest's electric reserve margins decline, volatility in supply and prices in the West increases and prices increase – sometimes spike
- First sign of challenges we are facing now was August 2020
  - On multiple days for multiple hours, prices began spiking to levels not seen since the California Energy crisis of the early 2000's.

Causes

- Escalating loss of spinning/thermal resources galvanized with retirement of Navajo Generating station 12/2019
  - California rolling blackouts of 2020
- Fundamentals remain normal
  - Natural gas on margin
  - Trading at $2.00 - $4.00 range
- Trading purely on risk of another blackout
- Nobody wants to pay LD on another $3,000/MWh event
- Markets reward scarcity
  - Mesa must evaluate its participation in the market

Mesa Summer Purchases

- RFP in February resulted in a purchase in base energy for $55 - $59/MWh during Q1, Q2, Q4 and $90/MWh during Q3-22 and Q3-23

Product	Results	Prior Price	Purchase Price/Market Price
Base 15 MW	3 bidders, purchased through Brookfield	$32.75/MWh	$
Summer Peak (May – Sept)	No Bids	$39	
July-August Peak	No Bids	$65	
Dispatchable Product	No Bids	N/A	

- Western making purchase via RFP
  - $13.5M to make 3 month purchase in advance