INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Wednesday, September 21, 2022
TIME: 1:47 p.m. – 4:32 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 20

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

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TRANSCRIBED BY: Joann Bunze		PREFILED PAGES:	---
DATE FILED: September 27, 2022		TOTAL PAGES:	133

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, September 21, 2022

TIME: 1:47 p.m. - 4:32 p.m.

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BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and
Duke Energy Carolinas, LLC,
2022 Biennial Integrated Resource Plans
and Carbon Plan

VOLUME: 20

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

APPEARANCES Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:

Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:
Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:
Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

APPEARANCES Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

A P P E A R A N C E S Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:
Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:
Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

APPEARANCES Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

APPEARANCES Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

APPEARANCES Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

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Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

APPEARANCES Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

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Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

APPEARANCES Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

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1250 I Street Northwest, Suite 1000
Washington, DC 20005

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Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

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Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

APPEARANCES:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

APPEARANCES Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

APPEARANCES Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:
Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:
Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

APPEARANCES Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

APPEARANCES Cont'd.:

FOR APPALACHIAN VOICES:
Catherine Cralle Jones, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

FOR REDTAILED HAWK COLLECTIVE, ROBESON COUNTY COOPERATIVE FOR SUSTAINABLE DEVELOPMENT, ENVIRONMENTAL JUSTICE COMMUNITY ACTION NETWORK, and DOWN EAST ASH ENVIRONMENTAL AND SOCIAL JUSTICE COALITION:
Ethan Blumenthal, Esq.
ECB Holdings LLC
1624 Nandina Comers Alley
Charlotte, North Carolina 28205

FOR NC WARN and
FOR CHARLOTTE-MECKLENBURG NAACP:
Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

APPEARANCES Cont'd.:

FOR BROAD RIVER ENERGY, LLC:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

FOR KINGFISHER ENERGY HOLDINGS, LLC, and
FOR PERSON COUNTY, NORTH CAROLINA:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

Kurt Olson, Esq.
The Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616

APPEARANCES Cont'd.:

FOR THE CITY OF ASHEVILLE and COUNTY OF BUNCOMBE:
Jannice Ashley, Esq., Senior Assistant City Attorney
City Attorney's Office
70 Court Plaza
Asheville, North Carolina 28801

Curt Euler, Esq., Senior Attorney II
Buncombe County
200 College Street, Suite 100
Asheville, North Carolina 28801

FOR MAREC ACTION:
Bruce Burcat, Esq, Executive Director
MAREC Action
Post Office Box 385
Camden, Delaware 19934

Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

APPEARANCES Cont'd.:

FOR TOTALENERGIES RENEWABLES USA, LLC, and
FOR CLEAN ENERGY BUYERS ASSOCIATION:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough LLP
4140 Parklake Avenue, Suite 200
Raleigh, North Carolina 27612

Weston Adams, Esq.
Nelson, Mullins, Riley & Scarborough LLP
1320 Main Street, Suite 1700
Columbia, South Carolina 29201

FOR PORK COUNCIL:
Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR COUNCIL OF CHURCHES:
James P. Longest, Jr., Esq.
Duke University School of Law
Box 90360
Durham, North Carolina 27708

APPEARANCES Cont'd.:

FOR AVANGRID RENEWABLES, LLC:
Benjamin Smith, Esq.
Todd S. Roessler, Esq.
Joseph S. Dowdy, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR SEAN LEWIS:
Sean Lewis, Pro se
640 Firebrick Drive
Cary, North Carolina 27519

FOR THE USING AND CONSUMING PUBLIC, THE STATE, AND ITS CITIZENS:
Margaret Force, Esq., Special Deputy Attorney General
Tirrill Moore, Esq., Assistant Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

Lucy Edmondson, Esq., Chief Counsel
Robert Josey, Esq.
Nadia L. Luhr, Esq.
Anne Keyworth, Esq.
William E.H. Creech, Esq.
William Freeman, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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E X H I B I T S

	IDENTIFIED/ADMITTED
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I/A NC WARN Reliability Panel Direct Cross Examination Exhibit 1

NC WARN, *et al.*'s Direct Cross-Examination Exhibits Marked and Moved into the Record During Reliability Panel

NC WARN, *et al.* introduced and moved the following exhibits into the record during the direct cross-examination of Duke's Reliability Panel, which panel's testimony concluded on September 21, 2022.

Exhibit Name	**Date Exhibit Introduced / Identified for the Record**	**Date Exhibit Moved and Admitted into the Record / Evidence**
NC WARN, *et al.* Reliability Panel Direct Cross-Examination Exhibit No. 1	September 21, 2022	September 21, 2022
NC WARN, *et al.* Reliability Panel Direct Cross-Examination Exhibit No. 2	September 21, 2022	September 21, 2022

DUKE ENERGY CAROLINAS, LLC
DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-100, SUB 179
(CARBON PLAN)
Public Staff Data Request No. 4
Date Requested: May 16, 2022
Date Due: May 26, 2022

Public Staff Technical Contact:	**Jeff Thomas** **Phone #: (919) 733-0885** **Email: jeff.thomas@psncuc.nc.gov**
	Bob Hinton **Phone #: (919) 733-0896** **Email: bob.hinton@psncuc.nc.gov**
	Jay Lucas **Phone #: (919) 733-0885** **Email: jay.lucas@psncuc.nc.gov**
Public Staff Legal Contacts:	**Nadia Luhr** **Phone #: (919) 733-0975** **Email: nadia.luhr@psncuc.nc.gov**
	Lucy Edmondson **Phone #: (919) 715-3803** **Email: lucy.edmondson@psncuc.nc.gov**

Please provide responses to this request in a searchable native electronic format (e.g., Excel, Word, or PDF files). If in Excel format, please include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title. Please also refer to Public Staff Data Request No. 1 for instructions for responding to this and all other Data Requests served on the Company by the Public Staff in the above-captioned proceeding.

Topic: Peak Load and Energy Forecasts

1. Please identify the Companies' 10 highest summer daily loads for the period from June 1, 2021, through September 30, 2021. For each of these loads, please provide the time, date, actual percentage of operating reserves available, actual lambda, MWH generation from solar units at time of daily peak load, system average cooling degree hours (69 degrees base) from 1:00 pm to 5:00 pm, minimum morning temperature on the day prior to the daily peak, and any MW reduction in the peak attributable to the activation of each Company's DSM programs.

2. Please identify the Companies' 10 highest winter daily loads for the period from December 1, 2021, through March 31, 2022. For each of these loads, please

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Direct Cross-Examination Exhibit No. 1

provide the time, date, actual percentage of operating reserves available, actual lambda, MWH generation from solar units at time of daily load, system 7:00 am to 8:00 am heating degree hours (59 degrees base) for the day of the peak, the 4:00 pm heating degree hours on the day prior to the peak, and any MW reduction in the peak attributable to the activation of each Company's DSM programs.

3. Please provide an analysis of DEC's and DEP's 2020 and 2021 summer peaks and 2020/2021 winter peaks. In the analysis, please explain any deviations between the predicted and normalized peak and include a brief description of factors that had a positive or negative impact on the peak load from the previous year. If available, the response should include the estimated impacts on residential, commercial, and industrial peak loads observed due to the COVID-19 pandemic.

4. Please provide an analysis of DEC's and DEP's 2021 and 2022 (to date) energy sales. Please explain any deviations between the predicted and normalized sales and include a brief description of factors that had a positive or negative impact on sales predictions from the previous year. If available, the response should include the estimated impacts on residential, commercial, and industrial energy sales due to the COVID-19 pandemic.

5. Please provide DEC's and DEP's 2017 through 2021 annual summer peaks and the weather normalized summer peaks for the same wholesale customer(s) included in the peak forecast filed in Docket No. E-100, Sub 147 (2016 IRP). If there has been an unplanned change in the Company's wholesale customers and other firm commitments since filing the 2016 IRP, please provide the annual MW contribution assumed with those wholesale customer(s) that were added or substracted. Please identify the average system temperature(s) assumed in the weather normalization of the summer peaks.

6. Please provide DEC's and DEP's 2014/2015 through 2020/2021 annual winter peaks and the weather normalized winter peaks for the same customer classes included in the peak forecast filed in the 2014 IRP. If there has been an unplanned change in the Company's wholesale customer load or firm commitments since filing the 2016 IRP, please provide the annual MW contribution assumed with those wholesale customer(s) that were added or subtracted. Please identify the system average temperature(s) assumed in the weather normalization of the winter peaks.

7. Please provide DEC's and DEP's 2017 through 2021 actual and weather normalized annual energy sales for the same customer classes included in the energy forecast filed in the 2016 IRP. If there has been an unplanned change in the Company's wholesale customers and other firm commitments since filing the 2016 IRP, please provide the annual MWh sales assumed with those wholesale customer(s).

8. Please provide DEC's and DEP's annual summer and annual winter peak demands as reported in the FERC Form 1 and the peaks reflected in the IRP for 2020-2022. In addition, provide a reconciliation with a brief explanation for any differences in the reported summer and winter peaks.

9. If available, please provide DEC's and DEP's Spring 2022 Forecast reports. If such reports are not available, please provide tables that graphically display the forecasted energy sales and peak demands for the individual classes and as provided in DEC's Spring 2012 Forecast filed in Docket No. E-100, Sub 137 (2012 IRP).

10. Please provide the equations with the summary statistics (including the influence option as with SAS and other software) used to generate the following forecasts for DEC and DEP:
    a. residential rates billed
    b. residential sales
    c. commercial rates billed
    d. commercial sales
    e. industrial rates billed
    f. industrial sales
    g. winter peak
    h. summer peak

    For a. - h. above, please include a brief description of the model, documentation of the variables, sources, publication dates of the forecast data, historical data used in the regression analysis, and forecast data in an Excel spreadsheet. For any independent variable that involves the combination of two or more variables, please provide the source data and a brief description of the variables with any calculations that underlie the data series.

    Please provide detailed documentation that describes the assumptions for the Cool and Heat variables in the monthly peak demand equations. This response should include assumptions that underlie the customer's responsiveness for both heating and cooling. In addition, the response should identify Itron's data sources for end-use appliances used to quanify the number of service area customers who rely on all-electric heat sources and the customers who rely other sources of heat; such as, natural gas, propane, and wood.

11. Please provide the capacity of behind the meter solar projected for the Company's residential, commercial, and industrial customer classes, and capacity's impact on peak demand and total energy, in years 2022-2037. Please include the expected capacity factor of behind the meter solar installations and provide supporting documentation and calculations for the behind the meter solar capacity projections.

12. Please provide any electric vehicle-related adjustments by customer class to DEC's and DEP's peak demand and energy sales forecasts, including but not limited to: the EV charging profiles used; coincident and non-coincident peak load; and annual energy sales associated with the charging of electric vehicles for years 2022-2037. Please include supporting documentation and calculations for the projections of EV adoption and charging profiles, including contribution to system peak load and total energy consumed. This response should also include a discussion of the types, use, and distribution of chargers (e.g., proportion of Level 1, Level 2, or DC Fast chargers; charging at home or at work, etc).

13. Has Duke considered the impact of electrification in the broader economy in its load and energy sales projections? Please provide a discussion and quantification of this impact and explain how it was estimated, or provide an explanation as to why it was not included.

14. Please provide the nominal and inflation adjusted total disposable income for DEC's and DEP's service area as incorporated in the forecasts, along with the energy sales and peak demand equations. Please identify the source of the data.

15. Please provide the nominal and inflation adjusted price of electricity incorporated in DEC's and DEP's forecasts.

16. Please provide a detailed description of the appliance saturation and efficiency variable(s) used in the peak and energy sales equations for DEC and DEP. Please identify the source of the data series. If the data is developed outside of the Companies, please provide the data and contact information at Itron (or relevant forecaster) who is familar with the historical data underlying the data used in the regression analysis.

17. Please list and provide an explanation for any change or enhancement that has been implemented since filing the 2020 IRP to (a) the summer and winter peak demand forecasting models, and (b) the energy sales forecasting models.

18. Please provide DEC's and DEP's historical residential kWh usage per customer for each year from 2019-2021 on an actual basis and a weather normalized basis.

19. Please provide DEC's and DEP's forecasted residential kWh usage per customer for each year from 2022-2037, both before and after the effects of energy efficiency and DSM programs.

Public Staff
Docket No. E-100, Sub 179
2022 Carbon Plan
Public Staff Data Request No. 4
Item No. 4-2
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please identify the Companies' 10 highest summer daily loads for the period from June 1, 2021, through September 30, 2021. For each of these loads, please provide the time, date, actual percentage of operating reserves available, actual lambda, MWH generation from solar units at time of daily peak load, system average cooling degree hours (69 degrees base) from 1:00 pm to 5:00 pm, minimum morning temperature on the day prior to the daily peak, and any MW reduction in the peak attributable to the activation of each Company's DSM programs.

RESPONSE:

Please see the attached file 'PSDR 4-2.xlsx' for the requested information.

PSDR%204-2.xlsx

Responder: Jeffrey A. Day, Lead Load Forecasting Analyst

2. Please identify the Companies' 10 highest winter daily loads for the period from December 1, 2021, through March 31, 2022. For each of these loads, please provide the time, date, actual percentage of operating reserves available, actual lambda, MWH generation from solar units at time of daily load, system 7:00 am to 8:00 am heating degree hours (59 degrees base) for the day of the peak, the 4:00 pm heating degree hours on the day prior to the peak, and any MW reduction in the peak attributable to the activation of each Company's DSM programs.

DEC Top 10 Highest 2021/2022 Winter Daily Loads

Top 10 Daily Loads	Date	Hour	7-8 am HDDs	4pm Day Prior HDDs	DSM Activiations
16,282	1/27/2022	8:00:00 AM	35.00	13.332	0
15,987	1/27/2022	9:00:00 AM	35.00	13.332	0
15,763	1/12/2022	8:00:00 AM	31.33	15.665	0
15,621	1/27/2022	7:00:00 AM	35.00	13.332	0
15,473	1/12/2022	9:00:00 AM	31.33	15.665	0
15,423	2/9/2022	8:00:00 AM	31.00	5.999	0
15,415	2/15/2022	8:00:00 AM	31.33	7.331	0
15,351	1/30/2022	9:00:00 AM	38.33	24.664	0
15,298	1/30/2022	8:00:00 AM	38.33	24.664	0
15,240	1/23/2022	8:00:00 AM	36.67	22.332	0

DEP Top 10 Highest 2021/2022 Winter Daily Loads

Top 10 Daily Loads	Date	Hour	7-8 am HDDs	4pm Day Prior HDDs	DSM Activiations
13,148	1/23/2022	8:00:00 AM	39.70	22.39	0
12,988	1/23/2022	7:00:00 AM	39.70	22.39	0
12,971	1/30/2022	8:00:00 AM	41.15	23.45	0
12,875	1/23/2022	9:00:00 AM	39.70	22.39	0
12,851	1/23/2022	6:00:00 AM	39.70	22.39	0
12,746	1/27/2022	8:00:00 AM	35.22	14.41	0
12,718	1/30/2022	7:00:00 AM	41.15	23.45	0
12,625	1/30/2022	9:00:00 AM	41.15	23.45	0
12,597	1/23/2022	5:00:00 AM	39.70	22.39	0
12,529	1/21/2022	7:00:00 PM	28.41	9.41	0

I/A

NC WARN Reliability Panel Direct Cross Examination Exhibit 2

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Sep 27 2022

FINAL

Root Cause Analysis

Mid-August 2020 Extreme Heat Wave

January 13, 2021

California ISO

Prepared by:
California Independent System Operator
California Public Utilities Commission
California Energy Commission

NC WARN, *et al.* Reliability Panel
Direct Cross-Examination Exhibit No. 2

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January 13, 2021

The Honorable Gavin Newsom
Governor, State of California
State Capitol
Sacramento, CA 95814

Dear Governor Newsom:

In response to your August 17, 2020 letter, the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC) are pleased to provide you the attached Final Root Cause Analysis (Final Analysis) of the two rotating outages in the CAISO footprint on August 14 and 15, 2020. This Final Analysis builds on the Preliminary Root Cause Analysis report published on October 6, 2020 and provides updates on the progress made on a number of the recommendations identified in the preliminary analysis. It also incorporates data that was not available when the preliminary analysis was developed, information from the Labor Day weekend heat wave and updated analysis of resource performance.

We recognize our shared responsibility for the power outages many Californians unnecessarily endured. The findings of the Final Analysis underscore this shared responsibility and give greater definition to actions that can be taken to avoid or minimize the impacts to those we serve.

The Final Analysis confirms there was no single root cause of the August outages, but rather, finds that the three major causal factors contributing to the outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. Although this combination of factors led to an extraordinary situation, our responsibility and commitment going forward is to be better prepared for extreme climate change-induced weather events and other operational challenges facing our evolving power system.

The Final Analysis provides recommendations for immediate, near and longer-term improvements to our resource planning, procurement, and market practices, many of which are underway. These actions are intended to ensure that California's transition to a reliable, clean, and affordable energy system is sustained and accelerated. This is an imperative – for our citizens, communities, economy, and environment. Implementation of these recommendations will involve processes within state agencies and the CAISO, partnership with the state Legislature, and collaboration and input from stakeholders within California and across the western United States.

This Final Analysis has served as an important step in learning from the events of August 14 and 15, as well as a clear reminder of the importance of effective communication and coordination.

We remain committed to meeting California's clean energy and climate goals and value your personal engagement on these issues and your unequivocal commitment and leadership on addressing climate change.

Regards,

Elliot Mainzer
President and Chief Executive Officer
California Independent System Operator

Marybel Batjer
President
California Public Utilities Commission

David Hochschild
Chair
California Energy Commission

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GLOSSARY OF ACRONYMS

ACRONYM	DEFINITION
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
A/S	Ancillary Services
AWE	Alerts, Warnings, and Emergencies
BA	Balancing Authority
BAA	Balancing Authority Area
BPM	Business Practice Manual
CAISO	California Independent System Operator Corporation
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CDWR	California Department of Water and Power
CEC	California Energy Commission
CHP	Combined Heat and Power
COI	California Oregon Intertie
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
DMM	CAISO Department of Market Monitoring
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
ESP	Energy Service Provider
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HASP	Hour-Ahead Scheduling Process
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor Owned Utility
IRP	Integrated Resource Planning
JASC	Joint Agency Steering Committee
LADWP	Los Angeles Department of Water and Power
LMS	Load Management Standards
LOLE	Loss of Load Expectation
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MW	Megawatt
MWD	Metropolitan Water District
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Corporation

ACRONYM	DEFINITION
NOB	Nevada Oregon Border
NQC	Net Qualifying Capacity
NWS	National Weather Service
PDCI	Pacific DC Intertie
PDR	Proxy Demand Resource
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PIME	Price Inconsistency Market Enhancements
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
QC	Qualifying Capacity
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource
RMO	Restricted Maintenance Operations
RMR	Reliability Must Run
RUC	Residual Unit Commitment
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge
TOU	Time of Use
WAPA	Western Area Power Administration
WECC	Western Electric Coordinating Council

Executive Summary

On August 14 and 15, 2020, the California Independent System Operator Corporation (CAISO) was forced to institute rotating electricity outages in California in the midst of a West-wide extreme heat wave. Following these emergency events, Governor Gavin Newsom requested that, after taking actions to minimize further outages, the CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) report on the root causes of the events leading to the August outages.

The CAISO, CPUC, and CEC produced a Preliminary Root Cause Analysis (Preliminary Analysis) on October 6, 2020, and have since continued their analysis to confirm and supplement their findings. This Final Root Cause Analysis (Final Analysis) incorporates additional data analyses that were not available when the Preliminary Analysis was published, but does not substantively change earlier findings and confirms that the three major causal factors contributing to the August outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. In summary, these factors were the following:

1. The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Although August 14 and 15 are the primary focus of this Final Analysis because the rotating outages occurred during those days, August 17 through 19 were projected to have much higher supply shortfalls. If not for the leadership of the Governor's office to mobilize a statewide mitigation effort and significant consumer conservation, California was also at risk of further rotating outages on those days.

ES.1 Current Actions to Prepare for Summer 2021

The CAISO, CPUC, and CEC have already taken several actions and are continuing their efforts to prepare California for extreme heat waves next summer without having to resort to rotating outages. These actions include the following:

1) The CPUC opened an Emergency Reliability rulemaking (R.20-11-003) to procure additional resources to meet California's electricity demand in summer 2021. Through this proceeding, the CPUC has already directed the state's three large investor-owned utilities to seek contracts for additional supply-side capacity and has requested proposals for additional demand-side resources that can be available during the net demand peak period (*i.e.*, the hours past the gross peak when solar production is very low or zero) for summer 2021 and summer 2022. The CPUC and parties to the proceeding, including the CAISO, will continue to evaluate proposals and procurement targets for both supply-side and demand-side resources.

2) The CAISO is continuing to perform analysis supporting an increase to the CPUC's RA program procurement targets. Based on the analysis to date, the CAISO recommends that the targets apply to both the gross peak and the critical hour of the net demand peak period during the months of June through October 2021.

3) The CAISO is expediting a stakeholder process to consider market rule and practice changes by June 2021 that will ensure the CAISO's market mechanisms accurately reflect the actual balance of supply and demand during stressed operating conditions. This initiative will consider changes that incentivize accurate scheduling in the day-ahead market, appropriate prioritization of export schedules, and evaluate performance incentives and penalties for the RA fleet. The CAISO is also working with stakeholders to ensure the efficient and reliable operation of battery storage resources given the significant amount of new storage that will be on the system next summer and beyond. Through a stakeholder process, the CAISO will pursue changes to its planned outage rules.

4) The CPUC is tracking progress on generation and battery storage projects that are currently under construction in California to ensure there are no CPUC-related regulatory barriers that would prevent them from being completed by their targeted online dates. The CAISO will continue to work with developers to address interconnection issues as they arise.

5) The CAISO and CEC will coordinate with non-CPUC-jurisdictional entities to encourage additional necessary procurement by such entities.

6) The CEC is conducting probabilistic studies that evaluate the loss of load expectation on the California system to determine the amount of capacity that needs to be installed to meet the desired service reliability targets.

7) The CAISO, CPUC, and CEC are planning to enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand side efforts during extreme heat events.

8) Preparations by the CAISO, CPUC, and CEC are underway to improve advance coordination for contingencies, including communication protocols and development of a contingency plan. The contingency plan will draw from actions taken statewide under the leadership of the Governor's Office to mitigate the anticipated shortfall from August 17 through 19, 2020.

In the mid-term, for 2022 through 2025, the CAISO, CPUC, and CEC will continue to work toward: (1) planning and operational improvements for the performance of different resource types (such as batteries, imports, demand response, and so forth); (2) improvements to accelerate the deployment and integration of demand side resources; and (3) consideration of generation and transmission buildouts to evaluate options and constraints under the SB 100 scenarios. This planning will also account for the pending retirements of some existing natural gas units and the Diablo Canyon nuclear power plant.

For the longer term, 2025 and beyond, the CAISO, CPUC, and CEC are working closely together and with other regional stakeholders to establish a modernized, integrated approach to forecasting, resource planning and RA targets. The enhanced collaboration and alignment are to more fully anticipate events like last summer's climate change-induced extreme heat wave and better plan and account for the transitioning electricity resource mix necessary to meet clean energy goals. This is a statewide concern that requires assessing resource sufficiency and reliability for all of California. As such, building on the CEC's statewide statutory responsibilities, the CAISO, CPUC, and CEC will define and develop necessary assessments as part of the *Integrated Energy Policy Report (IEPR)*, to create improved understanding into statewide, and WECC-wide resource sufficiency.

To provide complete transparency into the various summer 2021 preparedness efforts underway, the CAISO, CPUC, and CEC will continue to report monthly to the California State Legislature as requested by the Chair of the Assembly Committee on Utilities and Energy, Chris Holden. In addition, the CAISO is holding monthly open stakeholder calls to discuss progress toward ensuring its readiness for next summer's high heat events.

Information and updates on these efforts can be found at:

http://www.caiso.com/about/Pages/News/SummerReadiness.aspx

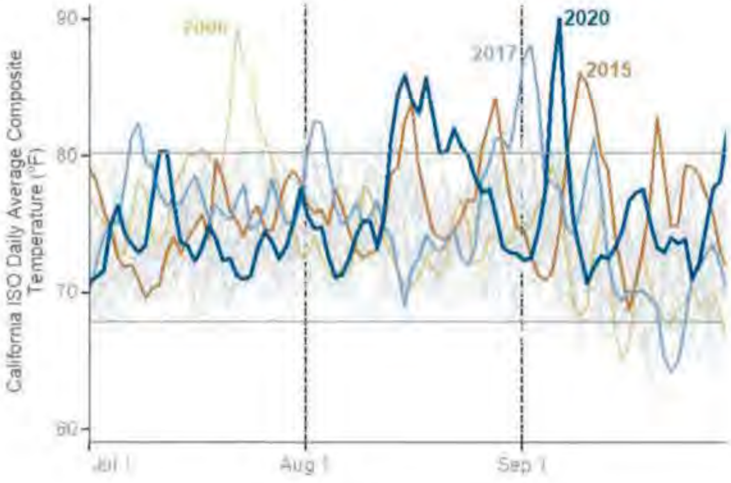
https://www.cpuc.ca.gov/summerreadiness/

ES.2 Three Major Factors that Led to Rotating Outages

1. *The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets*

Taking into account 35 years of weather data, the extreme heat wave experienced in August was a 1-in-30 year weather event in California. In addition, this climate change-induced extreme heat wave extended across the western United States. The resulting demand for electricity exceeded the existing electricity resource planning targets and resources in neighboring areas were also strained. As Figure ES.1 below shows this demand was the result of a historic West-wide heat wave.

Figure ES.1: July, August, and September Temperatures 1985 - 2020



Source: CEC Weather Data/CEC Analysis

2. *In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.*

The rotating outages both occurred after the period of gross peak demand, during the "net demand peak," which is the peak of demand *net of solar and wind generation* resources. With today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. This is because air conditioning and other load previously being served by solar comes back on the bulk electric system. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability, and this challenge is amplified during an extreme heat wave.

Since 2016, the CAISO, CPUC, and CEC have worked to examine the impacts of significant renewable penetration on the grid. By performing modeling that simulates each hour of the day, not just the gross peak, the RA program has adjusted for this change in resource mix by identifying reliability problems now seen later in the day during the net demand peak. However, additional work is needed to ensure that sufficient resources are available to serve load during the net peak period and other potential periods of system strain.

3. *Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.*

A subset of energy market practices contributed to the inability to obtain or prioritize energy to serve CAISO load in the day-ahead market that could have otherwise relieved the strained conditions on the CAISO grid on August 14 and 15. The practices which obscured the tight physical supply conditions included under-scheduling of demand in the day-ahead market by load serving entities or their scheduling coordinators, and convergence bidding, a form of financial energy trading used to converge day-ahead and real-time pricing. In addition, the CAISO implemented a market enhancement in prior years. In combination with real-time scheduling priority rules, this enhancement inadvertently caused the CAISO's day-ahead Residual Unit Commitment process to fail to detect and respond to the obscuring effects of under-scheduling and convergence bidding during August's stressed operating conditions. Although the CAISO is now actively developing solutions to these market design issues, most of the day-ahead supply challenges encountered were addressed in the real-time market as a result of additional cleared market imports, energy imbalance market transfers and other emergency purchases.

ES.3 Summary of Performance of Different Types of Resources

Since the Preliminary Analysis was published, the CAISO, CPUC and CEC completed their analysis of how specific resource types performed during the August and September extreme heat waves. The additional analysis and potential improvements are provided below for each resource type.

- Natural gas – Under very high temperatures, ambient derates are not uncommon for the natural gas fleet, and high temperatures reduce the efficiency of these resources. The CEC hosted a workshop to explore potential technology options for increasing the efficiency and flexibility of the existing natural gas power plant fleet to help meet near-term electric system reliability and the longer-term transition to renewable and zero-carbon resources.[1] Subsequently, the CPUC issued a ruling intended to get the most out the existing

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[1] See: https://www.energy.ca.gov/event/workshop/2020-12/morning-session-technology-improvements-and-process-modifications-lead and https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop

gas fleet in its recently opened procurement rulemaking focused on summer 2021 resources.[2] All reasonable efforts should be made to increase the efficiency of the existing fleet.

- Imports – In total, import bids received in the day-ahead market were between 40 to 50% higher than imports under RA obligations, which indicates that the CAISO was relying on imports that did not have a contract based obligation to offer into the market. In addition to the rule changes the CPUC made to the RA program with regard to imports for RA year 2021, the CPUC may consider additional changes to current import requirements.
- Hydro and pumped storage – RA hydro resources provided above their RA amounts and various hydro resources across the state managed their pumping and usage schedules to improve grid reliability. There should be increased coordination by communicating as early as possible the need for additional energy or active pump management ahead of stressed grid conditions and leverage existing plans for efficiency upgrades to improve electric reliability.
- Solar and wind – The CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour. Improvements to the RA program should account for time-dependent capabilities of intermittent resources.
- Demand response – While a significant portion of emergency demand response programs (reliability demand response resources or RDRR) provided load reductions when emergencies were called, the total amount did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO. Some, but not all of this difference, is the result of the credited amounts including a "gross up" that the CPUC applies to demand response resources consisting of approximately 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies. Additional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-ahead and real-time markets, and performance of dispatched demand response.
- Battery storage – During the mid-August events and in early September, there were approximately 200 MW of RA battery storage resources in the CAISO market. It is difficult to draw specific conclusions about fleet performance from such a small sample size. The CAISO will continue to track and understand the

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[2] CPUC, R.20-11-003, December 11, 2020 Ruling.

collective behavior of the battery storage fleet and work with storage providers to effectively incentivize and align storage charge and discharge behavior with the reliability needs of the system.

ES.4 Analyses Conducted Since the Preliminary Analysis

As mentioned, this final root cause analysis incorporates additional data analysis that was not available when the preliminary root cause analysis was published. Specifically, the following updates were made:

- Additional information and discussion of the Labor Day weekend extreme heat wave
- Updated temperature analysis (Section 4)
- Updated information on gas fleet resource forced outages during the extreme heat wave (Section 4)
- Discussion on performance of resources credited against RA requirements by CPUC and non-CPUC jurisdictional entities (Section 4 and Appendix B)
- Updated analysis of performance of demand response resources based on available settlement quality metered data (Section 4 and Appendix B)
- Updated analysis of load under-scheduling based on available settlement quality metered data and a survey of load scheduling entities, with recommendations (Section 4 and Appendix B)
- Updated recommendations on communications to utility distribution companies to ensure appropriate load reduction response during future critical reliability events and grid needs (Section 3)
- Discussion of performance of resources during the extreme heat wave (Section 4 and Appendix B)
- Update to discussion and Figures 4.2 and B.1 for actual metered load drop from demand response resources
- Additional analysis on net import position during August 14 and 15 (Appendix B)
- Corrections and clarifications:
    - Figures 4.4, B.16, B.17, B.18, and B.19 were all corrected because of a copy-and-paste error that repeated day-ahead awards data for each of these charts comparing real-time awards data. This change does not affect the shown RA amounts or actual generation data.

- The cause of a major transmission line outage in the Pacific Northwest was a storm in May 2020. The line remained derated through the mid-August extreme heat wave.
- Table 5.1 was amended with the correct forecast and peak numbers, and additional September dates were added.

In addition, since the publication of Preliminary Analysis, on November 24, 2020, the CAISO's Department of Market Monitoring (DMM) released its independent review of system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020, and some of the findings in the DMM report are incorporated into this Final Analysis.[3] Notably, the DMM concurred with many of the key findings and recommendations of the Preliminary Analysis and confirmed that there was no single root cause but a series of factors that contributed to the emergencies. The DMM also confirmed that "[c]ontrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation."[4]

ES.5 Conclusion

This Final Analysis provides a comprehensive look at the causes of the rotating outages on August 14 and 15, assesses how resources performed during those periods, and sets forth important recommendations and actions that are being addressed by the CAISO, CPUC and CEC. All three organizations have committed to working expeditiously and collaboratively, with the valuable input and engagement of critical partners and stakeholders, to position California for success in reliably meeting its climate and energy goals.

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[3] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[4] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 3.

1 Introduction

On August 17, 2020 Governor Gavin Newsom sent a letter to the California Independent System Operator (CAISO), the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) after the CAISO balancing authority area (BAA) experienced two rotating outages on August 14 and 15 during a West-wide extreme heat wave.[5] In the letter, Governor Newsom requested immediate actions to minimize rotating outages as the extreme heat wave continued, and a comprehensive review of existing forecasting methods and resource adequacy requirements. The Governor also requested that the CAISO complete an after-action report to identify root causes of the events.

The CAISO, CPUC, and CEC responded to Governor Newsom in a letter dated August 19, 2020, with immediate actions for the next five days and a commitment to an after-action report.[6] This Final Root Cause Analysis (Final Analysis) responds to that commitment and reflects the collective efforts of the CAISO, CPUC, and CEC.

The information provided in this Final Analysis reflects the best available assessment at this time.

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[5] *See* Office of the Governor, Letter from Gavin Newsom to Marybel Batjer, Stephen Berberich, and David Hochschild, August 17, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-Letter-to-CAISO-PUC-and-CEC.pdf.

[6] *See* CPUC, CAISO, and CEC, Letter from Marybel Batjer, Stephen Berberich, and David Hochschild to Governor Gavin Newsom, August 19, 2020, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/Joint%20Response%20to%20Governor%20Newsom%20Letter%20August192020.pdf.

2 Background

The CAISO is the Balancing Authority that oversees the reliability of approximately 80% of California's electricity demand and a small portion of Nevada. The remaining 20% is served by publicly owned utilities such as the Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), which operate separate transmission and distribution systems. However, there are some California publicly-owned utilities in the CAISO's BAA and some investor-owned utilities that do not. The CAISO manages the high-voltage transmission system and operates wholesale electricity markets for entities within its system and across a wider western footprint via an Energy Imbalance Market (EIM). The CAISO performs its functions under a tariff approved by the Federal Energy Regulatory Commission (FERC) and reliability standards set by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Corporation (NERC).

Utilities and other electric service providers operate within a hybrid retail market. Within the hybrid retail market, there are a variety of utilities, some of which fall under the direct authority of the CPUC, others that are subject to some CPUC jurisdiction but also have statutory authority to control some procurement and rate setting decisions, and other public or tribal entities that operate wholly independently of the CPUC or other state regulatory bodies for procurement and rate setting.

2.1 Resource Adequacy Process in the CAISO BAA

Following the California Electricity Crisis in 2000–2001, the Legislature enacted Assembly Bill (AB) 380 (Núñez, Chapter 367, Statutes of 2005), which required the CPUC, in consultation with the CAISO, to establish resource adequacy (RA) requirements for CPUC jurisdictional load serving entities (LSEs). The RA program primarily ensures there are enough resources with contractual obligations to ensure the safe and reliable operation of the grid in real time providing sufficient resources to the CAISO when and where needed. The RA program also encourages through incentivizes the siting and construction of new resources needed for future grid reliability.

Broadly speaking, the CPUC sets and enforces the RA rules for its jurisdictional LSEs and the community choice aggregators and electric service providers within the jurisdictional LSE's footprint, including establishing the electricity demand forecast basis and planning reserve margin (PRM) that sets the monthly obligations. CPUC jurisdictional LSEs must procure sufficient resources to meet these obligations based on the resource counting rules established by the CPUC. The CEC develops the electricity demand forecasts used by the CPUC and provided to the CAISO. Non-CPUC jurisdictional LSEs in the CAISO footprint can set their own RA rules regarding resource procurement requirements including the PRM and capacity counting rules or default to the CAISO's requirements. RA capacity from CPUC and non-CPUC jurisdictional LSEs are shown to the CAISO every month and annually based on operational and market rules established by the CAISO. The CAISO enforces these rules to ensure it can reliably operate the wholesale electricity market.

The CPUC and the CAISO require LSEs to acquire three types of (RA) products: System, Local, and Flexible. Although Local and Flexible RA play important roles in assuring reliability, the August 14 through 19 events implicated primarily system resource needs, and, therefore, system RA requirements. This Final Root Cause Analysis focuses on issues associated with system RA.

Separate from the RA programs, California has established a long-term planning process, known as the Integrated Resource Planning (IRP) process, through statutes and CPUC decisions. Under IRP, the CPUC models what portfolio of electric resources are needed to meet California's Greenhouse Gas (GHG) reduction goals while maintaining reliability at the lowest reasonable costs. The IRP models for resource needs in the three- to 10-year time horizons. If the IRP identifies a need for new resources, the CPUC can direct LSEs to procure new resources to meet those needs.

The RA and IRP programs work in coordination. The RA program is designed to ensure that the resources needed to meet California's electricity demand are under contract and obligated to provide electricity when needed. The IRP program ensures that new resources are built and available to the shorter-term RA program when needed to meet demand and to ensure the total resource mix is optimum to meet the three goals of clean energy, reliability, and cost effectiveness.

The RA rules are set to ensure that LSEs have resources under contract to meet average peak demand (a "1-in-2 year" peak demand) plus a 15% planning reserve margin (PRM) to allow 6% in Western Electricity Coordinating Council (WECC)-required grid operating contingency reserves, and a 9% contingency to account for plant outages and higher-than-average peak demand. The demand forecasts are adopted by the CEC as part of its *Integrated Energy Policy Report* (IEPR) process. To develop CPUC RA obligations, the adopted IEPR forecast may be adjusted for load-modifying demand response, as determined by the CPUC.

Like RA, IRP modeling is also based on the CEC's adopted 1-in-2 demand forecast plus a 15% PRM. In addition, the CPUC conducts reliability modeling based on a 1-in-10 Loss of Load Expectation (LOLE) standard, which is more conservative than the 1-in-2 demand forecast.

2.2 CEC's Role in Forecasting and Allocating Resource Adequacy Obligations

The CEC develops and adopts long-term electricity and natural gas demand forecasts every two years as part of the IEPR process. The CEC develops and adopts new forecasts in odd-numbered years, with updates in the intervening years. The inputs, assumptions and methods used to develop these forecasts are presented and discussed publicly at various IEPR workshops throughout each year.

Since 2013, the CEC, the CPUC, and the CAISO have engaged in collaborative discussions around developing the IEPR demand forecast and its use in each organization's respective planning processes. Through the Joint Agency Steering Committee (JASC), the three organizations have agreed to use a "single forecast set" consisting of baseline forecasts of annual and hourly energy demand, specific weather variants of annual peak demand, and scenarios for additional achievable energy efficiency (AAEE).[7] For 2020, the CEC used the 1-in-2 Mid-Mid Managed Case Monthly Coincident Peak Demands (mid-case sales and mid-case AAEE), adopted in January 2019. This was the most recently adopted forecast at when the RA process for 2020 began in early 2019 and follows the single forecast set agreement.

Using the adopted CAISO transmission access charge (TAC) area forecast as a basis, the CEC then determines the individual LSE coincident peak forecasts that are the basis for each LSE's RA obligations. In California, each TAC area is the equivalent to the IOU footprint. The CEC adjusts each LSE's load forecast for system coincidence by month. The RA system requirement is based on this coincident peak load.

This process is implemented differently for CPUC-jurisdictional LSEs, which include Investor-Owned Utilities (IOUs), Community Choice Aggregators (CCAs), and Energy Service Providers (ESPs), and non-CPUC-jurisdictional LSEs. These non-CPUC jurisdictional LSEs are primarily publicly owned utilities (POUs), but also include entities such as the California Department of Water Resources, the Western Area Power Administration (WAPA) and tribal utilities, each of which is its own local regulatory authority (LRA).[8]

For CPUC-jurisdictional LSEs, the CEC develops the reference total forecast and LSE-specific coincidence adjusted forecasts. To determine the reference forecast, CEC

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[7] The 2018 single forecast set—which informed the determination of LSE requirements for 2020 system RA—also included additional achievable scenarios around PV adoption induced by the 2019 Title 24 building standards update. Following adoption of the standards in 2019, the impact from these systems has been embedded in the baseline demand forecasts.

[8] As of 2020, there are 70 LSEs in the CAISO, of which 33 are non-CPUC jurisdictional. In total, the non-CPUC jurisdictional entities serve about 9% of CAISO load. See Appendix A, Table A2 for details.

staff disaggregates the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) transmission area peaks to CPUC- and non-CPUC-jurisdictional load based on the CEC forecast of the annual IOU service area peak demand (CEC Form 1.5b) and analysis of LSE hourly loads and year-ahead forecasts. The CPUC-jurisdictional total, adjusted for load-modifying demand response programs, serves as the reference forecast for the CPUC RA forecast process. CEC staff then reviews and adjusts CPUC LSE submitted forecasts consistent with CPUC rules. The final step in this process is applying a pro-rata adjustment to ensure the sum of the CPUC-jurisdictional forecasts is within 1% of the reference forecast.

The CEC develops a preliminary year-ahead forecast for the aggregate of Non-CPUC jurisdictional entity load as part of the CPUC reference forecast. Non-CPUC-jurisdictional entities then submit their own preliminary year-ahead forecasts of non-coincident monthly peak demands and hourly load data in April of each year. CEC staff determines the coincidence adjustment factors, and the resulting coincident peak forecast plus each non-CPUC-jurisdictional entity's PRM (which most set equivalent to the CAISO's default 15% PRM) determines the entity's RA obligation. Non-CPUC-jurisdictional entities, as their own LRA, may revise their non-coincident peak forecast before the final year-ahead or month-ahead RA showings to CAISO. The CEC-determined coincidence factors are applied to the new noncoincident peak forecast. For the final year-ahead RA showings to the CAISO, the non-CPUC-jurisdictional collective August 2020 coincident peak load was 4,170 MW, 3.7% lower than the CEC's preliminary estimate of 4,330 MW. For the August 2020 month-ahead showing, non-CPUC-jurisdictional forecasts increased to 4,169 MW. The CEC then transmits both non-coincident and coincident forecasts to the CAISO to ensure that congestion revenue rights allocations, based on non-coincident forecasts, are consistent with RA forecasts. The CEC transmits preliminary forecasts for all LSEs for the month of the annual peak (currently September) to CAISO by July 1. The load share ratios of the preliminary coincident forecasts are used to allocate local capacity requirements.

In August, CPUC LSEs may update their year-ahead forecast only for load migration. The CEC applies the same adjustment and pro-rata methodology to determine their final year-ahead forecasts. The CEC may also receive updated forecasts from POUs. The final coincident peak forecasts for all LSEs are transmitted to the CAISO in October to validate year-ahead RA compliance obligation showings. Throughout the year, LSEs may also update month-ahead forecasts. Coincident and non-coincident forecasts are transmitted to the CAISO each month. Non-coincident forecasts are the basis for allocations of congestion revenue rights. Table 2.1 summarizes this process.

Table 2.1: RA 2020 LSE Forecast Timeline

January 2019	Adopted 2018 IEPR Update TAC Area Monthly peak demand forecast
February – May	All LSEs submit preliminary forecasts of 2021 monthly peak demand and 2018 hourly loads. CEC develops jurisdictional split.
July 2019	Preliminary forecasts to LSEs; September load ratio shares to CAISO for local capacity allocation
August 2019	CPUC LSEs submit revised forecasts, updated only for load migration.
September 2019	CEC issues adjusted CPUC LSE forecasts, which must sum to within 1% of reference forecast.
	POUs may update non-coincident peak forecasts
October 2019	Year-ahead showing to CAISO
November 2019 - November 2020	LSEs may submit revised non-coincident peak forecasts to CEC before the month-ahead showing.

2.3 CPUC's Role in Allocating RA Obligations to Jurisdictional LSEs

Under state and federal rules, the CPUC is empowered to set the RA requirements for its jurisdictional LSEs, which include the IOUs, CCAs, and ESPs. Collectively, these jurisdictional entities represent 90% of the load within the CAISO service territory.

Monthly and annual system RA requirements are derived from load forecasts that LSEs submit to the CPUC and CEC annually. Following the annual forecast submission, the CEC makes a series of adjustments to the LSE load forecasts to ensure that individual forecasts are reasonable and aggregated to within one percent of the CEC forecast. These adjusted forecasts are the basis for year-ahead RA compliance obligations. Throughout the compliance year, LSEs must also submit monthly load forecasts to the CEC that account for load migration. These monthly forecasts are used to calculate monthly RA requirements.

In October of each year, CPUC jurisdictional LSEs must submit filings to the CPUC's Energy Division demonstrating that they have procured 90% of their system RA obligations for the five summer months (May–September) of the following year. Following this year-ahead showing, the RA program requires that LSEs demonstrate procurement of 100% of their system RA requirements on a month-ahead basis. To determine the capacity of each resource eligible to be counted toward meeting the CPUC's RA requirement, the CPUC develops Qualifying Capacity (QC) values based on what the resource can produce during periods of peak electricity demand. The CPUC-adopted QC counting conventions vary by resource type:

- The QC value of dispatchable resources, such as natural gas and hydroelectric (hydro) generators, are based on the maximum output of the generator when operating at full capacity—known as the Pmax.
- Resources that must run based on external operating constraints, such as geothermal resources, receive QC values based on historical production.
- Combined heat and power (CHP) and biomass resources that can bid into the day-ahead market, but are not fully dispatchable, receive QC values based on historical MW amount bid or self-scheduled into the day-ahead market.
- Wind and solar QC values are based on a statistical model looking at the contribution of these resources to addressing loss of load events. This method is known as the effective load carrying capability (ELCC). This modeling has reduced the amount of qualifying capacity these resources receive by approximately 80% (that is, a solar or wind resource that can produce 100 MW at the maximum output level is assumed to produce only about 20 MW for meeting the CPUC's RA program).[9]
- Demand Response QC values are set based on historical performance.

The resultant QC value does not consider potential transmission system constraints that could limit the amount of generation that is deliverable to the grid to serve load. Consequently, the CAISO conducts a deliverability test to determine the Net Qualifying Capacity (NQC) value, which may be less than the QC value determined by the CPUC. RA resources must pass the deliverability test as the NQC value is what is ultimately used to determine RA capacity.

2.3.1 Timeline for RA Process, Obligations, and Penalties

System RA is based on a one-year cycle where procurement is set for one year forward.[10] In the year ahead (Y-1), the CEC adjusts each LSE's 1-in-2 demand forecast according to the process described above. The LSE's RA obligation is its forecast plus the PRM established by the CPUC or applicable LRA. Each CPUC jurisdictional LSE must then file an RA resource plan with the CPUC on October 31 of each year that shows the

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[9] CPUC, D.19-06-026, Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program, June 27, 2019, available at:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF

[10] Local RA has a three year forward requirement.

LSE has at least 90% of its RA obligations under contract for the five summer months of the following year. If a jurisdictional LSE submits an RA plan with the CPUC that does not meet its full obligations, the LSE can be fined by the CPUC.

The CEC staff uploads into the CAISO RA capacity validation system all the approved load forecasts for each CPUC-jurisdictional and non-jurisdictional LSE for each month of the year-ahead obligation. Credits to an LSE's obligation permitted by the LRA, may result in a lower amount of total RA shown by the LSE scheduling coordinator to the CAISO. Credits generally represent demand response programs and other programs that reduce load at peak times. These credits are not included in the forecasts transmitted by the CEC. The composition of credited amounts are generally not visible to the CAISO, and resources that are accounted for in the credits do not submit bids consistent with a must offer obligation and are not subject to availability penalties or incentives, or substitution requirements as described below.[11] Lastly, the CAISO will allocate the capacity of reliability must-run (RMR) backstop resources to offset LSE obligations, also described below.

Finally, RA submissions are provided to the CAISO as required for CPUC- and non-CPUC-jurisdictional LSEs via a designated scheduling coordinator. To participate in the CAISO market, an entity (whether representing an LSE, generation supplier, or other) must be a certified scheduling coordinator or retain the services of a certified scheduling coordinator to act on its behalf.[12] For the year-ahead RA obligation, scheduling coordinators for suppliers of RA capacity are required to submit a matching supply plan to the CAISO. The CAISO then combines the supply plans to determine if there are enough resources under contract to meet the planning requirements.

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[11] Since credited capacity is not subject to CAISO RA market rules, on August 27, 2020, the CAISO submitted proposed edits to its Business Practice Manual (BPM) for Reliability Requirements to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. Several stakeholders objected to the change and appealed the decision. On December 9, 2020, the CAISO BPM Appeals Committee decided to hold any changes in abeyance until August 1, 2021, to work constructively and collaboratively with stakeholders to attempt to resolve the stakeholders' and Appeals Committee's concerns. The CAISO will evaluate by August 1, 2021 whether the CAISO's expressed concerns about resource crediting have been addressed. *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0 and http://www.caiso.com/Documents/ExecutiveAppealsCommitteeDecision-PRR1280-Dec092020.pdf

[12] Scheduling coordinators can directly bid or self-schedule resources as well as handle the settlements process. *See* http://www.caiso.com/participate/Pages/BecomeSchedulingCoordinator/Default.aspx

All LSEs must also submit month-ahead RA plans 45 days before the start of each month showing that they have 100% of their system RA requirement under contract. The CPUC once again verifies the month-ahead supply plans and can fine LSEs that do not comply with its RA requirements. The CAISO also receives supply plans in the month-ahead time frame from the designated scheduling coordinators similar to the year-ahead time frame.

Under CAISO rules, if there are not enough resources on the supply plans, the CAISO can procure additional backstop capacity on its own to meet the planning requirements. To address supply plan deficiencies, the CAISO can procure additional resources through its capacity procurement mechanism (CPM). The CAISO procures CPM capacity through a competitive solicitation process. The CPM allows the CAISO to procure backstop capacity if LSEs are deficient in meeting their RA requirements or when RA capacity cannot meet an unforeseen, immediate, or impending reliability need.

In addition, the CAISO can procure backstop capacity through its RMR mechanism. The RMR mechanism authorizes the CAISO to procure retiring or mothballing generating units needed to ensure compliance with applicable reliability criteria. Once so designated, participation as an RMR unit is mandatory.

2.4 CAISO's Role in Ensuring RA Capacity is Operational

Resources providing system RA capacity generally have a "must-offer" obligation, which means they must submit either an economic bid or self-schedule to the CAISO day-ahead market for every hour of the day.[13] The CAISO tariff provides limited exceptions to this 24x7 obligation for resources that are registered with the CAISO as "Use-Limited Resources," "Conditionally Available Resources," and "Run-of-River Resources." Moreover, wind and solar resources providing RA capacity must bid consistent with the associated because the variability of these resources would not reflect full availability 24x7.

Resources providing RA capacity whose registered start-up times allow them to be started within the real-time market time horizon, referred to in the CAISO tariff as "Short Start Units" and "Medium Start Units," have a must-offer obligation to the real-time market regardless of the respective day-ahead market award. Resources with longer registered start times, referred to in the CAISO tariff as "Long Start Units" and "Extremely Long-Start Resources," have no real-time market bidding obligation if they did not receive a day-ahead market award for a given trading hour. This is because if they are

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[13] Additional CAISO market rules exist for flexible RA capacity.

not already online, the lead time for a dispatch from the real-time market is too short for these resources to respond.

The CAISO has two main mechanisms to ensure that resources providing RA capacity meet the must-offer obligation. First, the CAISO submits cost-based bids on behalf of resources providing generic RA capacity that do not meet the respective RA must-offer obligation. The generated bid helps ensure the CAISO market has access to energy from an RA resource even when that RA resource fails to bid as required. Second, through the RA Availability Incentive Mechanism (RAAIM), the CAISO assesses non-availability charges and provides availability incentive payments to generic and flexible RA resources based on whether their performance falls below or above, respectively, defined performance thresholds. The CAISO tariff exempts certain resource types from bid generation and RAAIM. The exemptions from bid generation, RAAIM, and the 24x7 generic RA must-offer obligation are not necessarily paired; a resource type can be exempt from one but still face the other two. Lastly, credited amounts do not have any RA market obligations because the underlying resources are not always visible to the CAISO and were not provided explicitly on the RA supply plans. Credited resources are accounted for as non-RA throughout this analysis.

Pursuant to section 34.11 of its tariff, the CAISO may issue exceptional dispatches (*i.e.*, manual dispatches by CAISO operators outside the CAISO's automated dispatch process) to resources to address reliability issues. The CAISO may issue a manual exceptional dispatch for resources in addition to or instead of resources with a day-ahead schedule during a System Emergency or to prevent a situation that threatens System Reliability and cannot otherwise be addressed.

3 Mid-August Event Overview

3.1 Weather and Demand Conditions During Mid-August

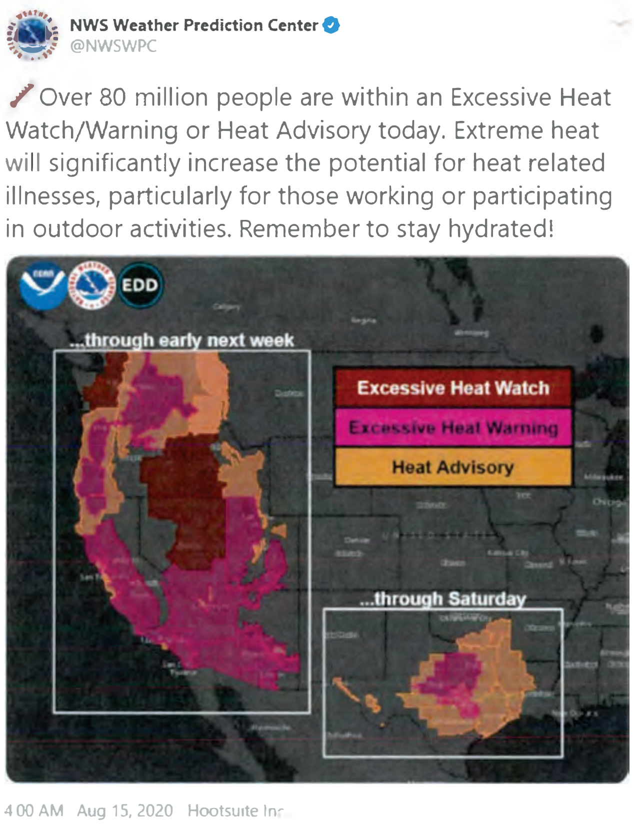
During August 14 through 19, California experienced statewide extreme heat with temperatures 10-20 degrees above normal. As Figure 3.1 below shows, this extreme heat affected 32 million California residents.

Figure 3.1: National Weather Service Sacramento Graphic for August 14

Source: https://twitter.com/NWSSacramento

In total, 80 million people fell within an excess heat watch or warning as shown in Figure 3.2 below from the National Weather Service (NWS).

Figure 3.2: National Weather Service Weather Prediction Center Graphic for August 15



NWS Weather Prediction Center
@NWSWPC

🌡 Over 80 million people are within an Excessive Heat Watch/Warning or Heat Advisory today. Extreme heat will significantly increase the potential for heat related illnesses, particularly for those working or participating in outdoor activities. Remember to stay hydrated!

4 00 AM Aug 15, 2020 Hootsuite Inc

Source: https://twitter.com/NWSWPC/status/1294589703254167557

The rest of the West also experienced record or near-record highs with forecasts ranging between five and 20 degrees above normal, with the warmest temperatures in the Southwest (Las Vegas and Phoenix) as well as the Coastal Pacific Northwest (Portland and Seattle). Figure 3.3 below documents the continuing extreme heat wave on August 18 into August 19.

Figure 3.3: National Weather Service Weather Prediction Center Graphic for August 18

NWS Weather Prediction Center
@NWSWPC

This loop of the past four days features over 140 cases where observed temperatures either tied or broke their previous daily record highs. More record high temps are being set this afternoon with yet another round of record breaking heat expected across the Southwest tomorrow.

Source: https://twitter.com/NWSWPC/status/1295824180638670848

This rare West-wide extreme heat wave affected demand for and supply of generation. Typically, high day-time temperatures are offset by cool and dry evening conditions. However, the multi-day extreme heat wave meant that there was limited overnight cooling, so air conditioners continued to run well into the evening and the next day. The CAISO also conducted a backcast analysis isolating the impacts of shelter-in-place and work-from-home conditions due to COVID-19.[14] The backcast analysis found that while load was lower in the spring months, during July, as air conditioning use increased, the CAISO observed minimal to no load reductions compared to pre-COVID-19 conditions.

In terms of supply, the extreme heat wave negatively impacted conventional generation (such as thermal resources fueled by natural gas), which typically operates less efficiently during temperature extremes. Even for solar generation, high clouds caused by a storm covering large parts of California and smoke from active fires during these events reduced large-scale grid-connected solar and behind-the-meter solar generation on some days, leading to increased variability. Lastly, California hydro

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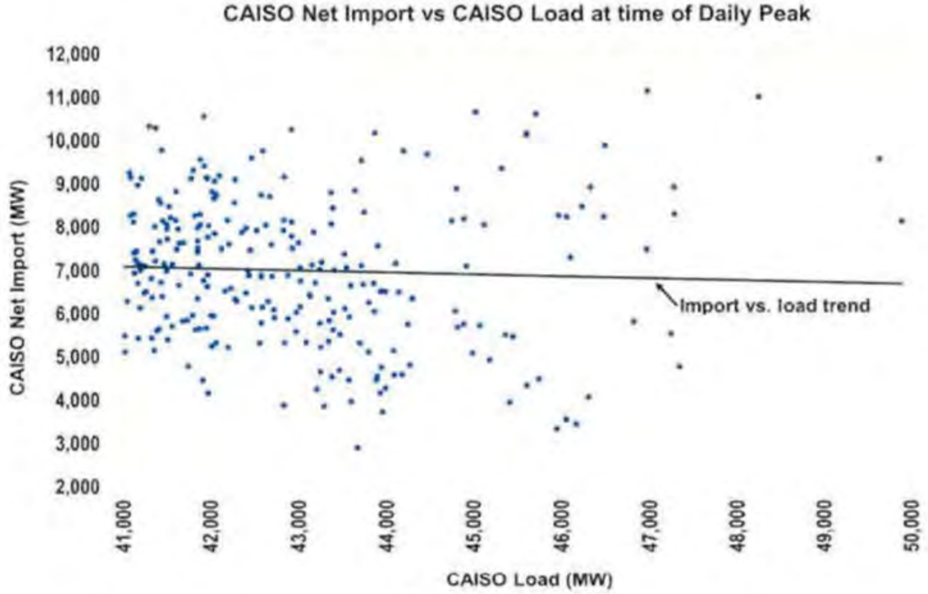
[14] *See* CAISO analysis: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf#search=covid

conditions for summer 2020 were below normal. The statewide snow water content for the California mountain regions peaked at 63% of average on April 7, 2020.

The CAISO Balancing Authority Area (BAA) traditionally relies on electricity imports on peak demand days, meaning that while electricity trading occurs with the rest of the West, on net, the CAISO imports more than it exports. During the extreme heat wave, given the similarly extreme conditions in some parts of the West, the usual flow of net imports into the CAISO was drastically reduced. The CAISO was also limited in its ability to access energy from the Northwest due to a derate at an intertie in the northern part of the system. Figure 3.4 below shows the historical trend of net imports into the CAISO footprint from 2017 through 2019 at the daily peak hour when demand is at or above 41,000 MW.[15] On average the import trend is about 6,000 MW to 7,000 MW of net imports, but this trend can vary widely and generally decreases as the CAISO load increases.

Figure 3.4: 2017 -2019 Summer Net Imports at Time of Daily Peaks Above 41,000 MW



Source: CAISO

3.2 CAISO Reliability Requirements and Communications During mid-August Event

This section provides an overview of relevant CAISO reliability requirements and related operations-based communications, as well as more general communications channels, used during the mid-August event.

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[15] Demand of 41,000 MW is 90 percent of the forecast of the CAISO 2020 1-in-2 peak demand of 45,907 MW.

The CAISO operates the wholesale electricity markets and is the Balancing Authority (BA) for 80% of California and a small portion of Nevada (CAISO-Controlled Grid). The CAISO operates to standards set by the North American Electric Reliability Corporation[16] (NERC) and the Western Electricity Coordinating Council[17] (WECC) regional variations as approved by the Federal Energy Regulatory Commission (FERC). Violations of WECC and NERC standards can result in FERC fines of up to $1 million per day.[18]

Specifically, under standard BAL-002-3[19] (NERC requirement) and BAL-002-WECC-2a[20] (WECC regional variance), the CAISO as the BA is required to have contingency reserves.[21] Contingency reserves are designated resources that can be dispatched to address unplanned events on the system such as a loss of significant generation, sudden unplanned outage of a transmission facility, sudden loss of an import, and other grid reliability balancing needs.[22] Contingency reserves are maintained to ensure the grid can respond quickly in case the CAISO loses a major element on the grid such as the Diablo Canyon Power Plant (Diablo Canyon) or the Pacific DC Intertie (PDCI) transmission line. The NERC and WECC standards specifically require the grid operators to identify the most severe single contingency that could destabilize the BAA and cause cascading outages throughout the western interconnected grid if that resource is lost. For the CAISO, the most severe single contingency tends to be either Diablo Canyon or the PDCI.

Generally, the CAISO is required to carry reserves equal to 6% of the load, consistent with WECC contingency requirements that operating reserves be equal to the greater of (1) the most severe single contingency or (2) the sum of three percent of hourly integrated load plus three percent of hourly integrated generation.[23] Under normal conditions, the CAISO uses two types of generating resources to meet this requirement: spinning and non-spinning reserves. Spinning reserves are generating resources that are running (*i.e.*, "spinning") and can quickly and automatically provide energy in case of a contingency. Non-spinning reserves are resources, which may include demand

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[16] https://www.nerc.com

[17] https://www.wecc.org

[18] *See* https://www.ferc.gov/enforcement-legal/enforcement/civil-penalties

[19] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf

[20] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-WECC-2a&title=Contingency%20Reserve&jurisdiction=United%20States

[21] Also referred to as operating reserves or ancillary services. This discussion does not include regulation up and down services.

[22] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[23] *See* https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-WECC-2a&title=Contingency%20Reserve&jurisdiction=United%20States

response, that are available to respond within 10 minutes but are not running pre-contingency. Under extraordinary conditions, it is possible for the CAISO to designate load that is not specifically designated as demand response resources and that can be curtailed within 10 minutes as non-spinning reserves, if the resources normally used are not available. Although the CAISO can curtail load to meet its reserve requirements, it can do so only for non-spinning reserves. Continuing to operate while lacking sufficient spinning reserves runs the risk that if an actual contingency were to occur, such as the loss of Diablo Canyon or PDCI, the CAISO BAA would lack the automatic response capability needed to stabilize the grid, leading to uncontrolled load shed that could potentially destabilize the greater western grid.

The CAISO's operational actions are communicated largely through Restricted Maintenance Operations (RMO), and Alerts, Warnings, and Emergencies (AWE) per Operating Procedure 4420.[24] Each is explained briefly below:

- **Restricted Maintenance Operations** request generators and transmission operators to postpone any planned outages for routine equipment maintenance and avoid actions that may jeopardize generator or transmission availability or both, thereby ensuring all grid assets are available for use.
- **Alert** is issued by 3 p.m. the day before anticipated contingency reserve deficiencies. The CAISO may require additional resources to avoid an emergency the following day.
- **Warning** indicates that grid operators anticipate using contingency reserves. Activates demand response programs (voluntary load reduction) to decrease overall demand.
- **Stage 1 Emergency** is declared by the CAISO when contingency reserve shortfalls exist or are forecast to occur. Strong need for conservation.
- **Stage 2 Emergency** is declared by the CAISO when all mitigating actions have been taken and the CAISO is no longer able to provide for its expected energy requirements. Requires CAISO intervention in the market, such as ordering power plants online.
- **Stage 3 Emergency** is declared by the CAISO when unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions through firm load shedding.

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[24] https://www.caiso.com/Documents/4420.pdf

In addition to these operational communication tools, the CAISO relies on Flex Alerts to broadly communicate with consumers to appeal for voluntary energy conservation when demand for power could outstrip supply. Starting in 2016, the administration of the Flex Alert program was entirely transferred from the IOUs to the CAISO without a paid media component.[25] However, between 2016 and 2019, the CPUC allocated up to $5 million per year to support paid Flex Alert advertising, as funded and administered by the Southern California Gas Company, because of the Aliso Canyon natural gas leak.[26] The funded Flex Alert advertising focused on customers in the Los Angeles area and eventually shifted to a focus on winter electricity conservation to reduce gas usage.[27] In February 2020, a new CPUC proceeding was opened to discuss Flex Alert funding in the Los Angeles area.[28]

During the mid-August event, the Flex Alert program was administered by the CAISO and is comprised of a website (www.flexalert.org), a Twitter account (twitter.com/flexalert, 8,000 followers), and placement of the Flex Alert logo and activation websites such as on the home page of caiso.com. Additional communication of the Flex Alert status was sent by the CAISO on the CAISO's Twitter account (twitter.com/California_ISO, 25,000 followers), market notices, and via the alert function of the CAISO's app. The CAISO's webpage, Twitter account, and app were also used to communicate RMO and AWE notifications. All Flex Alerts, RMO, and AWE notifications called by the CAISO since 1998 are posted online.[29]

The CAISO provided targeted outreach to the energy sector leadership in California. The CAISO also communicated with the load serving entities in the CAISO BAA, representatives of the market participants (*i.e.*, wholesale buyers and sellers of electricity), and BAs throughout the West on operational matters.

The CAISO received more than 400 media inquiries from international, national, and local mainstream and trade radio, television and print outlets, including *The UK Guardian*, *NBC News*, *CNN*, *Forbes*, *The Weather Channel*, *New York Times*, *Los Angeles Times*, *San Francisco Chronicle*, *Bloomberg*, *Reuters*, *Politico* and *National Public Radio*, as well as small and medium market media organizations throughout the West.
To manage the upsurge in media attention, the CAISO published 15 news releases from August 13 through 19, provided public statements about the August extreme heat

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[25] CPUC Decision 15-11-033, November 19, 2015.

[26] CPUC Decision 16-04-039, April 21, 2016.

[27] CPUC Decision 18-07-008, July 12, 2018.

[28] Scoping Memo was released for Application 19-11-018, Application of Southern California Gas Company for adoption of its 2020 Flex Alert Marketing Campaign, February 27, 2020.

[29] http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf

wave during a special CAISO Board of Governors meeting on August 17, and hosted three press briefings on August 17, 18, and 19.[30] Presentations and audio recordings were made available on a 2021 Summer Readiness webpage.[31] The CAISO also relies on its social media presence to inform, educate and update the public on load forecasts, shortage projections, Flex Alert status, stage emergency notifications, and conservation measures. The CAISO's Twitter following grew from slightly more than 14,000 to nearly 25,000 during August.

3.3 Sequence of Events of CAISO Actions

This section provides an overview of events and CAISO actions taken to operate through and communicate the conditions during the days preceding and following the August 14 and 15 events.

3.3.1 Before August 14

Wednesday, August 12
Before August 14, the CAISO began to anticipate higher load and temperatures than average in California and across the West. On August 12, the CAISO issued its first RMO for August 14 through 17 in anticipation of high loads and temperatures. The RMO cautioned market participants and transmission operators to avoid actions that may jeopardize generator or transmission availability or both.

Thursday, August 13
The CAISO issued a Flex Alert for August 14 calling for voluntary conservation from 3 p.m. to 10 p.m.

By 3 p.m., the CAISO issued a grid-wide Alert effective from 5 p.m. through 9 p.m. August 14, forecasting possible system reserve deficiency for those hours, requesting additional ancillary services and energy bids from market participants, and encouraging conservation. In addition to broader coordination, the CAISO provided customized outreach to PG&E, SCE, and San Diego Gas & Electric (SDG&E) and asked them to review the system outlook for August 14 through 17.

3.3.2 August 14

Friday's events

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[30] *See* http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E847D21D-54A0-4B54-9517-48B4EEA6DCED

[31] http://www.caiso.com/about/Pages/News/default.aspx#heatwave

The CAISO began the day coordinating with the various affected entities to discuss the day's outlook, availability and activation of emergency demand response, and possible need for emergency measures up to and including shedding load due to the high load forecast and resource deficiencies.

At 11:51 a.m. the CAISO re-issued a Warning effective August 14 from 5 p.m. through 9 p.m., still forecasting possible reserve deficiencies for those times and requesting additional ancillary services and energy bids. The CAISO reached out to PG&E, SCE, and SDG&E advising them that the CAISO anticipated the need to call on emergency demand response (Reliability Demand Response Resources [RDRR]) later that day. The CAISO operators contacted other BAs for potential emergency assistance.

At 2:57 p.m., a unit with full capacity of 494 MW recorded a forced outage because of plant trouble.[32] When the unit went out of service, it was generating 475 MW. The CAISO dispatched its contingency reserves to replace the lost energy. As explained above, contingency reserves as required by the NERC and WECC are designed to protect against a sudden loss of generation, unplanned outage of a transmission facility, or sudden loss of an import due to the loss of transmission.

Throughout this time, the CAISO operators continuously canvassed for additional unloaded capacity and potential emergency assistance from other BAs. CAISO operators requested neighboring BAs to increase the available transmission capacity to allow increased import capability into the CAISO BAA. As a result, the capacity on CAISO's share of the California Oregon Intertie (COI) was increased between 6:00 p.m. and 11:59 p.m. by 189 MW.

At 3:20 p.m. the CAISO enabled the RDRR in the real-time market. Unlike other resources in the resource adequacy program or in the market, RDRR can be accessed only by the CAISO after, at minimum, a Warning is issued. The programs that comprise the RDRR can be called only a limited number of times and for specific maximum durations. Accordingly, the CAISO must position these resources to be used when the need is greatest.[33] By enabling this pool of demand response, the RDRR was positioned to respond.

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[32] This unit was the Blythe Energy Center in Riverside County. The rotating outages were not caused by any single generator or resource type.

[33] For example, some programs are limited to one call per day, 10 calls per month, and a maximum of a six hour duration per call. Therefore, if the RDRR is called too early in the day, it may exhaust its response before the greatest need on the grid.

At 3:25 p.m., the CAISO declared a Stage 2 Emergency for the CAISO BAA from 3:20 p.m. to 11:59 p.m.[34]

Throughout this time, the CAISO was having difficulty maintaining the 6% WECC reserve requirement with generating resources and began to rely on meeting part of its requirement with firm load available to be shed within 10 minutes, counting it as non-spinning contingency reserves. The CAISO worked directly with PG&E, SCE, and SDG&E to designate roughly 500 MW as non-spinning contingency reserves based on a pro rata share.

By 5 p.m., conditions had not improved and the CAISO manually dispatched about 800 MW of RDRR. Per RDRR program requirements, the full response is required to be realized within 40 minutes following the dispatch, which is a request to respond. Actual metered response was 476 MW during the 5 p.m. hour increasing to 762 MW in the 6 p.m. hour.

By about 6:30 p.m., all demand response had been dispatched. The conditions still had not improved. Though the system peak load occurred at 4:56 p.m., throughout this time demand remained high, while solar generation was rapidly declining. The CAISO reached out to PG&E, SCE, and SDG&E to secure an additional 500 MW of load to be counted toward non-spinning contingency reserves (for a total of 1,000 MW).

At 6:38 p.m., the CAISO declared a Stage 3 Emergency because it was deficient in meeting its reserve requirement. The CAISO was not able to cure the deficiency with generation, because all generation was already online, and solar was rapidly declining while demand remained high. Because the CAISO was no longer able to maintain sufficient spinning reserves to address the loss of significant generation or transmission, the load shed was necessary to allow the CAISO to recover and maintain its reserves. If the CAISO continued to operate with the deficiency in spinning reserves, the CAISO risked causing uncontrolled load shed and destabilizing the rest of the western grid if during this time it lost significant generation or transmission. Consequently, the CAISO ordered two phases of controlled load shed of 500 MW each, based on a pro-rata share across the CAISO footprint for distribution utility companies. The distribution utility operators are responsible for carrying out the actual outages on their respective distribution systems.

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[34] The CAISO does not need to declare a Stage 1 before declaring either a Stage 2 or Stage 3 Emergency. Warning and Stage emergency declarations are based on operating conditions, which can change rapidly.

By 7:40 p.m., the CAISO began restoring previously shed load as system conditions had improved so that resources were adequate to meet the CAISO load and contingency reserve obligations.

At 8:38 p.m., the CAISO downgraded from a Stage 3 to Stage 2, and Stage 2 was cancelled at 9:00 p.m. The Warning expired at 11:59 pm.

Other Circumstances and Actions Taken

In addition to dealing with the effects of the extreme heat wave, throughout most of the day the CAISO was at risk of losing access to generation because of the numerous fires threatening the loss of major transmission lines, which would have further compromised its ability to serve demand reliably. For example, the Lake Fire was threatening the PDCI and Path 26, the Poodle Fire was also burning close to PDCI, and the Grove Fire was threatening transmission lines.

Under CAISO Operating Procedure 4420, a declaration of a Stage 2 Emergency allows the CAISO to request emergency assistance from other balancing authorities.

In preparation for the next day, the CAISO issued an Alert notice at 2:24 pm because of possible reserve deficiencies due to resource shortages between 5 p.m. and 9 p.m. on August 15.

3.3.3 August 15

Saturday's Events

The CAISO began the day coordinating with the various affected entities to discuss the day's outlook as California and the western region continued to experience extreme heat with high loads, availability and activation of their emergency demand response, and the possible need for emergency measures up to and including shedding load due to the high load forecast and resource deficiencies.

At 12:26 p.m. the CAISO issued a Warning effective 12:00 p.m. through 11:59 p.m. confirming the Alert issued the day before because conditions had not improved, and the forecasted load was trending higher. The CAISO noted possible reserve deficiencies due to resource shortages between 5 p.m. and 9 p.m., requested additional ancillary services and energy bids, and requested voluntary conservation.

Between 2 p.m. and 3 p.m., solar declined by more than 1,900 MW caused by storm clouds, while loads were still increasing and contingency reserves were down to minimal WECC requirements. *See* Figure 3.5 below. About 3 p.m. the CAISO manually dispatched almost 900 MW of RDRR in the real-time market. Note that this is different from the events of August 14, where RDRR was first accessed and then dispatched later. Here, the rapidly evolving situation led the CAISO to immediately dispatch the RDRR. Per RDRR program requirements, the full load drop response is expected to be realized within 40 minutes after dispatch. Actual metered response was 550 MW during the 3 p.m. hour increasing to 729 MW in the 4 p.m. hour.

Between 3 p.m. and 5 p.m. CAISO operators continuously canvassed for additional unloaded capacity and for potential emergency assistance from other BAs. CAISO operators requested neighboring BAs to increase the available transmission capacity to allow increased import capability into the CAISO BAA. As a result, the California Oregon Intertie capacity was increased from 3 p.m. to 10 p.m.

Between 5:12 p.m. and 6:12 p.m., wind generation declined by 1,200 MW (Figure 3.5 below). Like on August 14, the CAISO requested PG&E, SCE, and SDG&E to designate about 500 MW of 10-minute responsive load as non-spinning contingency reserve.

At 6:13 p.m. a generator unexpectedly ramped down generation from about 394 MW to about 146 MW, resulting in a loss of about 248 MW.[35] This was not an outage, but a ramp down from the CAISO dispatch, which the CAISO now understands to be due to an erroneous dispatch from the scheduling coordinator to the plant.

At 6:16 p.m., the CAISO declared a Stage 2 Emergency because like the day before, consistent with WECC standards, the CAISO was having difficulty maintaining the 6% WECC reserve requirement with generating resources and began to rely on meeting part of its requirement with firm load available to be shed within 10 minutes, counting it as non-spinning contingency reserves.

Like on August 14, the CAISO requested additional load from PG&E, SCE, and SDG&E to designate as non-spinning contingency reserve for about 1,000 MW.

At 6:28 p.m., the CAISO declared a Stage 3 Emergency because it was deficient in meeting its reserves requirement. The CAISO was not able to cure the deficiency with generation because all generation was already online, and solar was rapidly declining while demand remained high. Because the CAISO was no longer able to maintain sufficient spinning reserves to address the loss of significant generation or transmission, the load shed was necessary to allow the CAISO to recover and maintain its reserves. If the CAISO continued to operate with the deficiency in spinning reserves it risked causing uncontrolled load shed and destabilizing the rest of the western grid if during

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[35] This unit was the Panoche Energy Center in Fresno County. The rotating outages were not caused by any single generator or resource type.

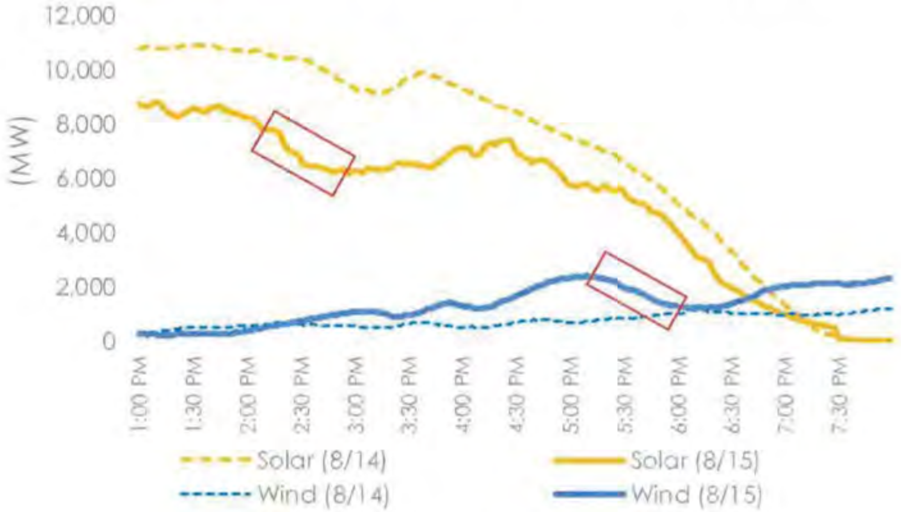
this time it lost significant generation or transmission.[36] Consequently, the CAISO ordered the distribution utility operators to execute about 500 MW of controlled load shed on their respective distribution systems.

At 6:48 p.m., the Stage 3 Emergency was cancelled because wind production had increased more than 500 MW and the CAISO ordered all previously shed load to be restored. The duration of the controlled load shed was 20 minutes. The CAISO eventually downgraded to a Stage 2, and Stage 2 was cancelled at 8 p.m. The Warning expired at 11:59 pm.

Other Circumstances and Actions Taken

Between 1 p.m. until 8 p.m., there was more solar generation on August 14 than August 15, and production was more consistent as shown in Figure 3.5 below. On the other hand, wind generation was lower on August 14 but steadily increasing.

Figure 3.5: Wind and Solar Generation Profiles for August 14 and 15



Source: CAISO

Throughout most of the day, transmission lines were impacted because of thunderstorms across the PG&E service territory.

Under Operating Procedure 4420, declaration of a Stage 2 Emergency allows the CAISO to request emergency assistance from other BAs.

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[36] To clarify, for example, this may mean the CAISO would be unable to recover area control error (ACE), frequency, voltage, etc.

In preparation for the next day, the CAISO issued an Alert notice at 2:55 pm because of possible reserve deficiencies between 5 p.m. and 9 p.m. on August 16.

3.3.4 August 16 through 19

From August 16 through 19, excessive heat was forecasted consistently for California. Consequently, the CAISO issued RMO and Alert notices from August 16 through 19, as well as a Flex Alert for the same days from 3 p.m. to 10 p.m. Warning notices were called and RDRR was dispatched from August 16 through 18. During this period various portions of the western region began to cool off, which meant that imports increased on those days. As a result, the most critical days were concentrated on Monday, August 17 and Tuesday, August 18 and the CAISO declared Stage 2 Emergencies for both days. However, controlled load shed and thus rotating outages were avoided.

On August 16, Governor Newsom declared a State of Emergency[37] because of the extreme heat wave in California and surrounding western states. The proclamation gave the California Air Resources Board maximum discretion to permit the use of stationary and portable generators, as well as auxiliary ship engines, to reduce load and increase generation through August 20. On August 17, Governor Newsom issued Executive Order N-74-20,[38] which suspended restrictions on the amount of power facilities could generate, the amount of fuel they could use, and air quality requirements that prevented facilities from generating additional power during peak demand periods through August 20.

As a result of the conservation messaging and awareness created by the State of Emergency, the state significantly reduced peak demand by as much as 4,000 MW (compared to day-ahead forecasts) on August 17 through 19, as shown in Figure 3.6 through Figure 3.8 below.

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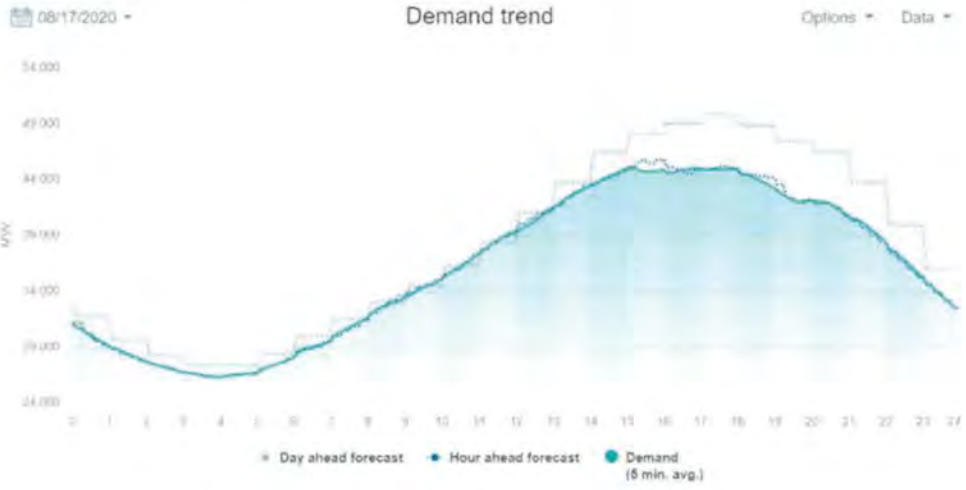
[37] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation-text.pdf

[38] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf

Figure 3.6: Comparison of Day-Ahead Forecast and Actual Demand for August 17

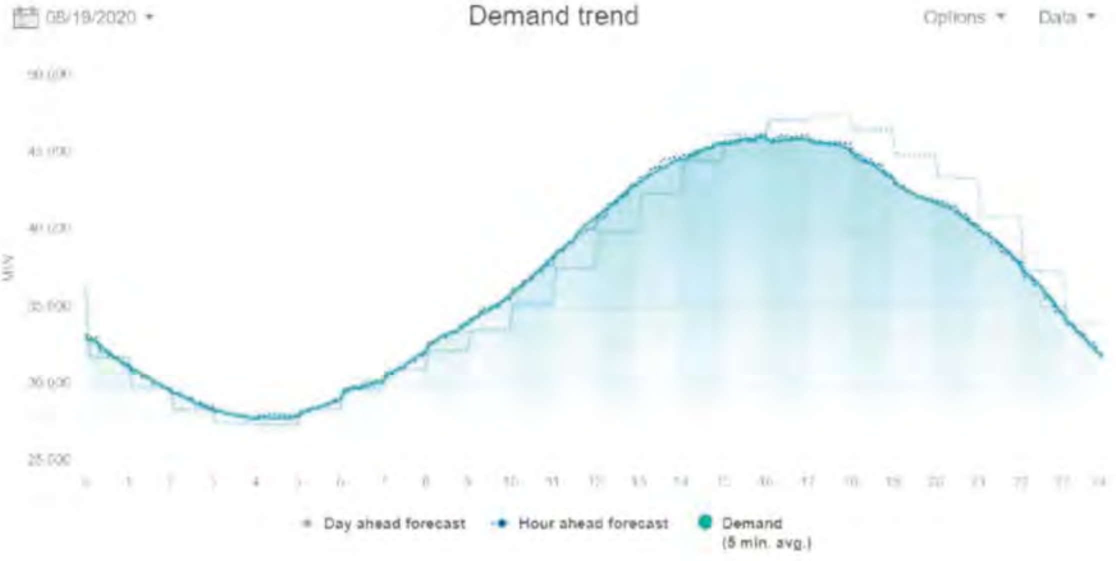


Source: CAISO

Figure 3.7: Comparison of Day-Ahead Forecast and Actual Demand for August 18

Source: CAISO

Figure 3.8: Comparison of Day-Ahead Forecast and Actual Demand for August 19



Source: CAISO

On August 17 the CAISO Board of Governors convened for a special session to provide an overview of system operations on August 14 and 15, followed by a question-and-answer session from the public and CAISO responses to submitted comments.[39] Subsequently on August 21 and 27, the CAISO held two public special sessions to address market-related questions.[40] Responses to questions were later posted online.[41]

See Section 5 for a discussion on capacity procurement mechanism procurement.

3.4 Number of Customers Affected by Rotating Outages

As noted earlier, CAISO called two successive 500 MW blocks of controlled load shed on August 14 for a total of one hour and one 500 MW block of controlled load shed on August 15 for 20 minutes. The controlled load shed requests were implemented as

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[39] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E847D21D-54A0-4B54-9517-48B4EEA6DCED

[40] http://www.caiso.com/Documents/SpecialSessionMarketUpdateQuestion-AnswerWebConference082120.html and http://www.caiso.com/Documents/UpdatedParticipationInformationMarketUpdateCall082720.html

[41] http://www.caiso.com/Documents/Aug14-15-StakeholderQandA.pdf

rolling outages for customers. On August 14, the load shed requests went out to all LSEs in the BAA (both CPUC- and non-CPUC-jurisdictional), and on August 15, the requests went out only to CPUC-jurisdictional LSEs, as the event was over before the request was submitted to other entities in the CAISO footprint. Table 3.1 and Table 3.2 below depict the number of CPUC-jurisdictional customers affected by the rotating outages, the amount of load shed requested by the CAISO, the amount of load shed, and the duration in total and for each IOU footprint. Neither the agencies nor the CAISO has visibility into the number of customers, amount of load shed, or duration for non-CPUC jurisdictional entities. Selected non-CPUC jurisdictional entities that were contacted before the issuance of this report stated that they did not shed load on either day.

The duration of rotating outages experienced by PG&E customers on both days significantly exceeds the load shed duration called by the CAISO. Because PG&E received less than 10 minutes' warning to begin shedding load, it implemented its operating instructions protocol (covered in NERC standard COM-002-4) rather than its rotating outage protocol, for which more than 10 minutes' advance warning is required. PG&E's operating instructions protocol required the implementation of manual switching using field personnel, resulting in longer-duration outages because of the need for manual restoration.

Table 3.1: CPUC-Jurisdictional Customers Affected by August 14 Rotating Outages

	Customers	**CAISO-initiated rotating outage (MW)**	**IOU actual response (MW)**	**Time (in mins)**	**Start**	**Finish**
SCE	132,000	400	400	63	6:56 PM	7:59 PM
PG&E	300,600	460	588	~150	6:38 PM	~9:08 PM
SDG&E	59,000	71.6	84	~15-60		
Total	**491,600**	**931.6**	**1,072**	**15 to 150 mins**		

Table 3.2: CPUC Jurisdictional Customers Affected by August 15 Rotating Outages

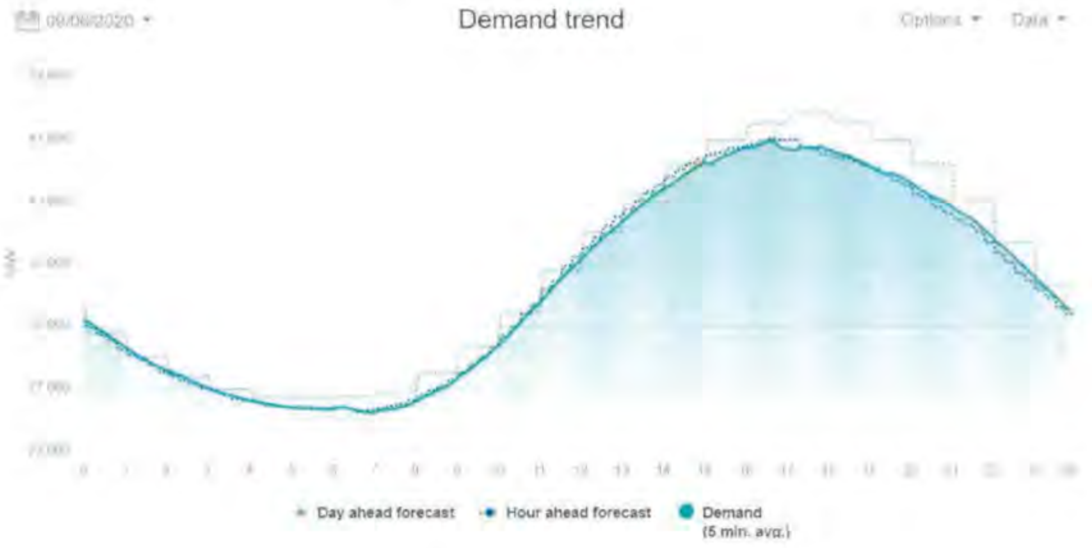
	Customers	**CAISO-initiated rotating outage (MW)**	**IOU actual response (MW)**	**Time (in mins)**	**Start**	**Finish**
SCE	70,000	200	200	8	6:43 PM	6:51 PM
PG&E	234,000	230	459	~90	6:25 PM	~7:55 PM
SDG&E	17,000	35.8	39	~15-60		
Total	**321,000**	**465.8**	**698**	**8 to 90 mins**		

As noted above, on August 14 the CAISO ordered two phases of controlled load shed based on a pro-rata share across the CAISO footprint for all utility distribution companies (UDCs). However, some of the smaller UDCs failed to respond. To ensure all UDCs appropriately respond to future critical reliability events and grid needs, the CAISO will implement the following improvements based on discussions with UDCs: (1) implement a process to periodically verify and test communication information and channels, (2) conduct trainings, and drills with UDCs to ensure familiarity with existing emergency processes not often used and clearly set expectations, and (3) streamline and/or automate processes that are manual and time-consuming.

3.5 September 6 and 7

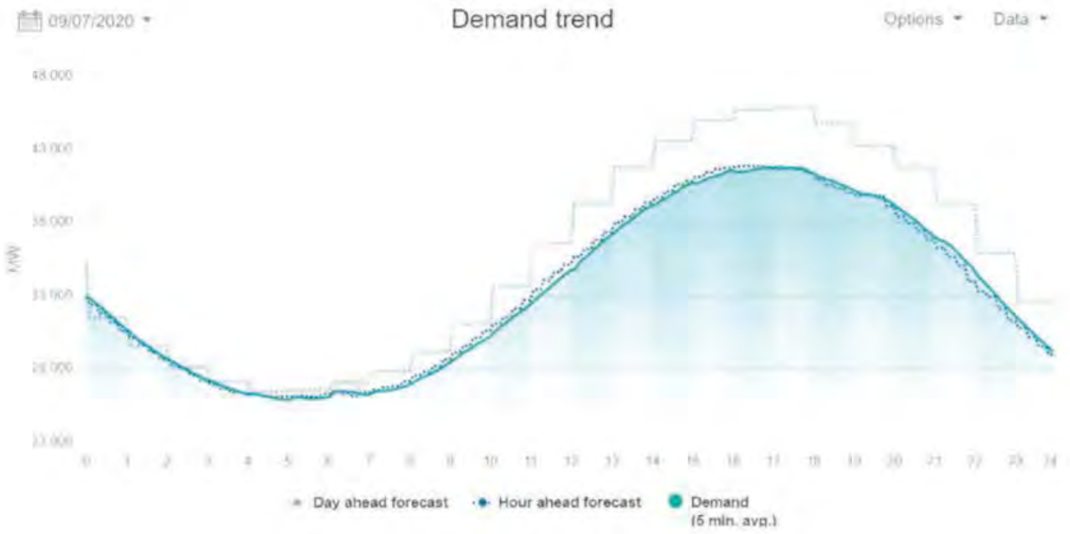
In addition to the extreme heat wave in mid-August, the CAISO footprint experienced another period of high temperatures and demand over the 2020 Labor Day weekend, especially on Sunday, September 6 and Monday, September 7. Similar to August 17 through 19, there was considerable conservation from the public which explains the large difference between the day-ahead load forecast versus the actual demand illustrated in Figure 3.9 and Figure 3.10 below. Actual data based on a one-minute basis are provided in Table 5.1.

Figure 3.9: Comparison of Day-Ahead Forecast and Actual Demand for September 6



Source: CAISO

Figure 3.10: Comparison of Day-Ahead Forecast and Actual Demand for September 7



Source: CAISO

4 Understanding of Various Factors That Contributed to Rotating Outages on August 14 and 15

This section provides the final analysis of the root causes of the rotating outages that were called on August 14 and 15. Several factors contributed to the need for these emergency measures. Consequently, there is no single root cause identified. Instead, this Final Root Cause Analysis (Final Analysis) identified the following challenges that all contributed to the emergency:

- The climate change-induced extreme heat wave across the western United States resulted in the demand for electricity exceeding the existing electricity resource adequacy (RA) and planning targets.
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
- Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

On November 24, 2020, the CAISO's Department of Market Monitoring (DMM) released its independent review of system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020.[42] The DMM concurred with many of the key findings and recommendations of the Preliminary Analysis and agrees that there was no single root cause but a series of factors that contributed to the emergencies. Of note, the DMM did not identify any individual generator and "[c]ontrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation."[43]

Additional analyses and details are provided in Appendix B.

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[42] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

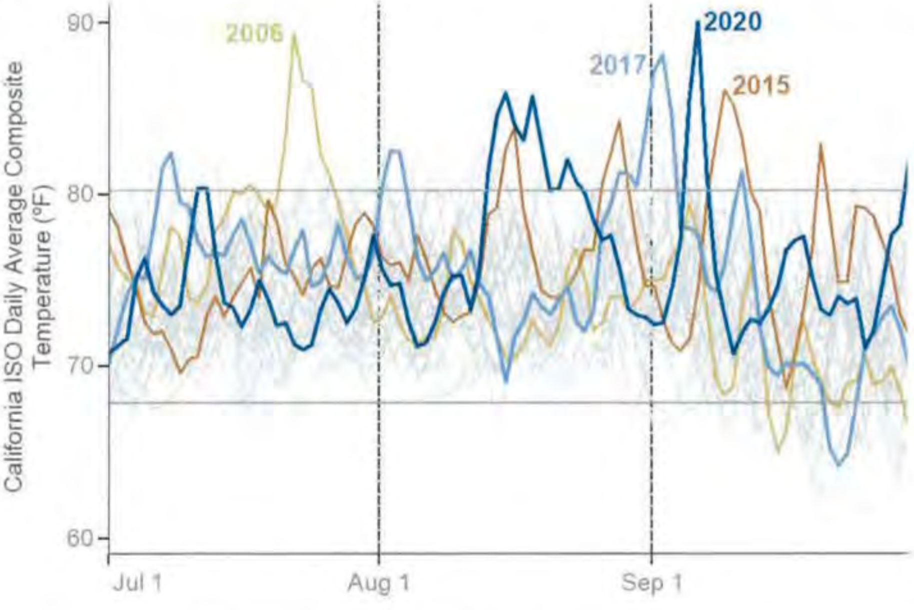
[43] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 3.

4.1 The Climate Change-Induced Extreme Heat Wave Across the Western United States Resulted in Demand for Electricity Exceeding Existing Electricity Resource Adequacy (RA) and Planning Targets

Between August 14 and August 19, 2020, the entire western United States experienced an extreme heat wave. During this period, California experienced four out of the five hottest August days since the CAISO and the CEC began tracking these data in 1985, as measured by the daily average temperature composite used to predict electricity consumption across the California ISO region. August 14 was the third-hottest August day; August 15 was the hottest. The only other period on record with a similar heat wave was July 21–25, 2006, which included three days above the highest temperature in August 2020.

Figure 4.1 shows daily temperatures for July through September for each year from 1985 to 2020. The middle 90% of temperatures is contained in the shaded gray region, and the six-day extreme heat wave for 2020's is shaded in light orange. August 2020 (dark blue) is distinguished from the year with the next-hottest days, 2015 (orange), by the magnitude and duration of the extreme heat wave. The hottest day in 2020 was a full degree and a half higher than that of 2015 – averaged over all hours of the day and across different parts of California – and six hottest days of 2020 came in succession, compared with two distinct heat waves in 2015 that each lasted just a day or two. In addition, as mentioned previously, the extreme heat wave spanned the western United States, which California typically relies on for electricity imports.

Figure 4.1: July, August, and September Temperatures 1985 - 2020



Source: CEC Weather Data/CEC Analysis

The current resource adequacy planning standards are based on a 1-in-2 peak weather demand plus a 15% PRM to account for changing conditions. Based on the CEC's revised analysis, taking into account 35 years of weather data, the extreme heat wave experienced in August was a 1-in-30 year weather event for August.[44] The September heat wave event was roughly a 1-in-70 event for that month.[45] The August extreme heat wave impacted the entire western United States for several days, combined with any energy demand impacts from COVID-19 that were not anticipated in the planning and resource procurement time frame, which is necessarily an iterative, multiyear process. The energy markets can help fill the gap between planning and real-time conditions, but the West-wide nature of this extreme heat wave limited the energy markets' ability to do so. Although this Final Analysis suggests that the rotating outages on August 14 and August 15 may have been avoided if some of the root causes identified in the remainder of this section had not occurred, it is unlikely that current RA planning levels would have avoided rotating outages for the demand forecasted for August 17 through August 19 without the extraordinary measures described in Section 5.

4.2 In Transitioning to a Reliable, Clean, and Affordable Resource Mix, Resource Planning Targets Have Not Kept Pace to Ensure Sufficient Resources That Can Be Relied Upon to Meet Demand in the Early Evening Hours. This Made Balancing Demand and Supply More Challenging During the Extreme Heat Wave

As discussed in Section 2, all LSEs in the CAISO's BAA based their reliability planning on a 1-in-2 average weather forecast. The CPUC's RA program is based on a 1-in-2 average forecast plus a 15% planning reserve margin (PRM). The forecast used in the RA program is based on the single forecast set developed by the CEC. The CEC sets the forecast for the CAISO footprint and works with load serving entities to set the individual coincident forecasts for RA. Based on the established methodology and timelines, the August 2020 obligation was based on the August 2018 IEPR Update transmission area monthly peak demand forecast of 44,955 MW, adjusted down to 44,741 MW and entered into the CAISO system by CEC staff as 44,740 MW. Table 4.1 below shows the breakdown between CPUC-jurisdictional LSEs and non-CPUC local regulatory authority (LRA) obligations and the resources and credits used to meet those obligations.

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[44] The RA obligation is planned for a 1-in-2 weather and adds a 15% PRM, in part to act as buffer for deviations from the 1-in-2 weather event.

[45] Including a trend in temperature to account for climate change, however, makes these events more probable. After accounting for such trends, the August extreme heat wave was a 1-in-20 event, and the September event was a 1-in-40 event.

Table 4.1: August 2020 RA Obligation, Shown RA, RMR, and Credits

CPUC	Non-CPUC	Total	
40,570	4,169	**44,740**	CEC forecast for 1-in-2 August 2020 (adjusted)
6,086	588	**6,674**	Total 15% planning reserve margin
46,656	4,758	**51,413**	Total obligation
44,763	4,164	**48,926**	August 2020 system resource adequacy shown
261	29	**290**	Reliability Must Run (RMR) contracted resources
1,632	565	**2,197**	Credits provided by local regulatory authorities
46,656	4,758	**51,413**	Total resource adequacy, RMR, and credits

The CPUC jurisdictional LSEs comprise approximately 91% of the total load. Per the CPUC's RA program requirements, a 15% PRM is added to the peak of the 1-in-2 forecast for a total obligation of 46,656 MW. The non-CPUC local regulatory authorities vary slightly in their PRM requirements but collectively yield a 14% PRM for a total obligation of 4,758 MW. About 500 MW or about 1% of the total load uses a PRM less than 15%. In total, across both CPUC-jurisdictional and non-jurisdictional entities, the PRM is 14.9% and the obligation for August 2020 was 51,413 MW.

There are three categories used to meet the total obligation. The most straightforward is the resource adequacy resources "shown" to the CAISO. This means the physical resource (either generation or demand response) is provided on a supply plan with the unique resource identification number (resource ID) to the CAISO system and noted as specifically meeting the August 2020 obligation. The second category of resources is Reliability Must Run (RMR) allocations from the CAISO. RMR resources are contracted by the CAISO under a reliability need and the capacity from these resources are allocated to the appropriate load serving entities to offset their obligations. The last category is "credits" provided by the local regulatory authorities to the CAISO. A credit is essentially an adjustment the LRA has made to its resource adequacy obligation, which can be neutral or decrease the obligation. For example, the largest credited amount is from the CPUC at 1,482 MW, which reflects the various demand response programs from the IOUs, including the emergency-triggered RDRR. However, the composition of credited amounts is generally not visible to the CAISO and all credited amounts do not submit bids consistent with a must-offer obligation and are not subject to CAISO resource adequacy market rules such as RAAIM or substitution. Since credited resources are not shown directly on the RA supply plans, they are not considered RA supply and are reflected as non-RA capacity throughout this analysis.

After the publication of the Preliminary Analysis, the CAISO attempted to assess the performance of credited resources but found that aside from the CPUC-credited demand response, all other credited capacity was either not in the CAISO market (*i.e.*, behind-the-meter backup generators) or reflected contracted capacity also not visible to the CAISO. Therefore, it was not possible to assess of these resources. Performance of credited CPUC demand response is provided below.

Since credited capacity is not subject to CAISO RA market rules, on August 27, 2020, the CAISO submitted proposed edits to its Business Practice Manual (BPM) for Reliability Requirements to stop the practice of crediting and require all RA resources to be explicitly shown on the RA supply plans.[46] Several stakeholders objected to the change and appealed the decision.[47] On December 9, 2020, the CAISO BPM Appeals Committee decided to hold any changes in abeyance until August 1, 2021, to work constructively and collaboratively with stakeholders to attempt to resolve the stakeholders' and Appeals Committee's concerns.[48] The CAISO will evaluate by August 21, 2021 whether the CAISO's expressed concerns about resource crediting have been addressed.

4.2.1 Planning Reserve Margin Was Exceeded on August 14

As described in the background in Section 2, the 15% PRM in the RA program was finalized in 2004 to account for 6% contingency reserves needed by the grid operator with the remaining 9% intended to account for plant forced outages and higher than average demand. The PRM has not been revised since.[49]

Figure 4.2 below compares August 14 and 15 actual peak, outages, and 6% contingency reserve requirement against the total PRM for August 2020. For August 14, contingency reserves were actually 6.3%, which reflects the fact that the actual load was higher than the forecast. In other words, based on the forecasted load of 44,740 MW, 6% contingency reserves are 2,669 MW. However, on August 15, the actual peak was 46,802 MW and 6% is 2,808 MW. Compared to the original forecasted load, 2,808 MW is 6.3%.

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[46] See Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

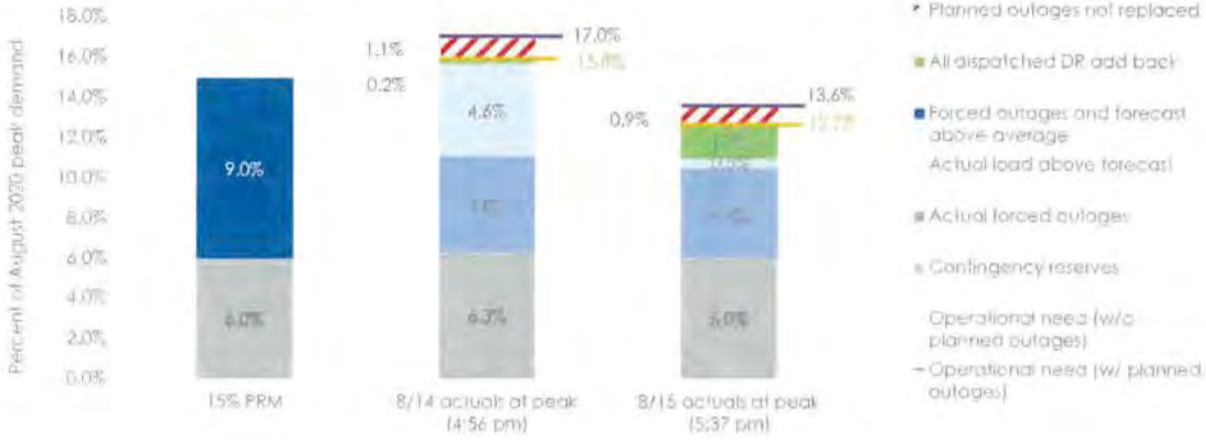
[47] See Appeals Committee information for PRR 1280: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AA347224-590D-47AC-ADA0-2E93A64CEF9C

[48] *See*: http://www.caiso.com/Documents/ExecutiveAppealsCommitteeDecision-PRR1280-Dec092020.pdf

[49] One difference from 2004 is the original PRM allocated 7% to contingency reserves. The CAISO does carry another 1% in regulation up requirements. However, for this analysis and to simplify the discussion, the 6% WECC requirement is used throughout.

On August 14 the actual load was 4.6% above forecast but does not include another 0.2% of load that was served by demand response. Adding back in the metered response of all demand response, load was 4.8% higher than forecasted. Total forced outages were 4.8%. Adding all of these elements, the operational need for August 14 was 0.8% higher than the 15% PRM. In addition to forced outages, during the actual operating day the CAISO also had 514 MW and 421 MW of planned outages that were not replaced on August 14 and 15, respectively. The CPUC-approved PRM does not include planned outages under the assumption that planned outages will be replaced with substitute capacity or denied during summer months. Adding the planned outages would increase the operational need to 2.0% higher than the PRM. On the other hand, the operational need for August 15 was below the 15% PRM by 2.3% including only forced outages and 1.4% with planned outages.

Figure 4.2: August 2020 PRM and Actual Operational Need During Peak (Updated)



Although a PRM comparison is informative, the rotating outages both occurred after the peak hour, as explained below.

4.2.2 Critical Grid Needs Extend Beyond the Peak Hour

The construct for RA was developed around peak demand, which until recently has been the most challenging and expensive moment to meet demand. The principle was that if enough capacity was available during peak demand, there would be enough capacity at all other hours of the day as well, since most resources could run 24/7 if needed. With the increase of use-limited resources such as solar generation in recent years, however, this is no longer the case. Today, the single critical period of peak demand is giving way to multiple critical periods during the day, including the net demand peak, which is the peak of load net of solar and wind generation resources. The RA program has also tried to adjust for this change in resource mix by identifying reliability problems now seen later in the day by simulating each hour of the day, not just peak, and identifying the risk of lost firm load called Loss of Load Expectation (LOLE). The evaluation of wind and solar generation in particular is evaluated on the Effective Load Carrying Capability (ELCC), which reflects the ability of generators to provide value at times when there is risk of lost firm load, now including later evening times. However, these ELCC values are still translated into static NQC values. This means, for example, that solar is typically under-valued during the peak but over-valued later in the evening after sunset.

Since 2016, the CAISO, CEC, and the CPUC have worked to examine the impacts of significant renewable penetration on the grid. Solar generation in particular shifts "utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by solar generation, with generation dropping off quickly as the evening hours approach."[50] Furthermore, as the sun sets, demand previously served by behind-the-meter solar generation is coming back to the CAISO system while load remains high. Consequently, on hot days, load later in the day may still be high, after the gross peak has passed, because of air conditioning demand and other load that was being served by behind-the-meter solar coming back on the system. As a result of declining behind-the-meter and front-of-meter (utility scale) generation in the late afternoon, after the peak demand hour of the day, demand is decreasing at a slower rate than net demand is increasing, which creates higher risk of shortages around 7 p.m., when the net demand reaches the peak (net demand peak).

Figure 4.3 shows on August 14, the net demand peak of 42,237 MW is 4,565 MW lower than the peak demand, but wind and solar generation have decreased by 5,438 MW during the same period. On August 15, the system peak is again before 6 p.m. and the net demand peak is slightly earlier at 6:26 p.m. The net demand peak is 41,138 MW, 3,819 MW lower than the peak demand, while wind and solar generation have decreased by 3,450 MW during the same period.

The net demand peak shown is already reduced by the impact of emergency demand response that had been triggered by this time. The difference between the demand curve (in blue) and the net demand curve (in orange) is largest in the middle of the day (around 10 a.m. until 4 p.m.) when renewables are generating at the highest levels and serving a significant amount of CAISO load. Most importantly, the rotating outages coincide closely with the net demand peaks.

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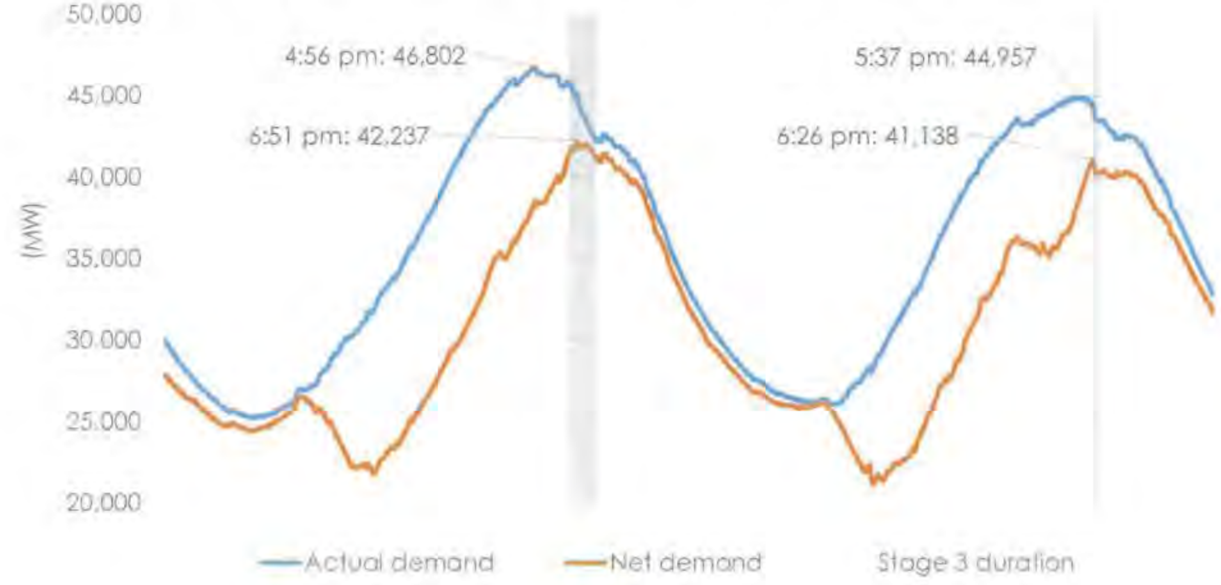
[50] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017, p. 51.

Figure 4.3: Demand and Net Demand for August 14 and 15

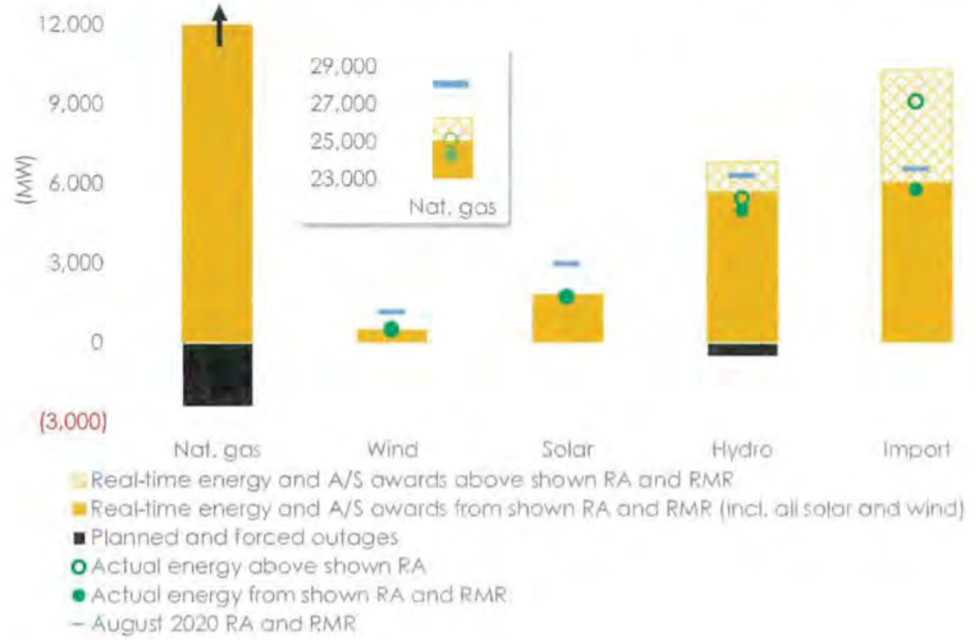


On August 14, the CAISO declared a Stage 3 Emergency at 6:38 p.m., right before the net demand peak at 6:51 p.m. Similarly, on August 15, the Stage 3 Emergency was called at 6:28 p.m., just after the net demand peak at 6:26 p.m.

4.2.3 Supply, Market Awards, and Actual Energy Production by Resource Type

This section discusses issues affecting planned RA versus actual energy supply resources that received awards in the day-ahead markets and ultimately provided energy on August 14 and 15. The focus is on the largest resource types: natural gas, imports, hydro, solar and wind generation. Resources totaling about 106% of the LSEs' total August RA obligations bid into the day-ahead market and resources equaling 101% of RA obligations received awards to provide energy or ancillary services in the day-ahead market, though not all this capacity is under RA contract. Of these totals, approximately 90% of shown RA capacity received an award. Figure 4.4 overlays three different time periods for the net demand peak on August 14. It shows how the different types of resources performed during the net demand peak. The blue markers show the levels of capacity expected to provide energy either as RA or RMR for August 2020. The solid yellow bars show where resources obligated to provide energy under RA requirements were expected to produce based on instructions issued in the CAISO's real-time market. The yellow cross-hatched bars show the same targets for resources that bid into the market but were not obligated to offer their energy. The black bars show planned and forced outages. The actual energy delivered based is shown by green circles.

Figure 4.4: August 14 Net Demand Peak (6:51 p.m.) August 2020 Shown RA and RMR, Real-time Awards, and Actual Energy Production (corrected)



Based on CAISO rules, only resources shown to the CAISO as RA are considered RA capacity. RA resources that generate above the shown amounts or resources with RA long-term contracts that are not shown to the CAISO are not considered RA resources under CAISO rules. Two simplifying assumptions were made for the analyses. First, all wind and solar generation is assumed to count toward RA capacity. Second, rather than classify all remaining bids and generation as non-RA, the analyses below classify such bids and generation more broadly as "above RA."[51]

The DMM's independent review of system conditions from mid-August to early September differentiated the "above RA" bids into three categories: (1) RA resources bidding above the RA shown amounts; (2) resources within the CAISO not shown as RA

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[51] Except for the more detailed export analysis in Appendix B, this Final Analysis does not distinguish resources within the "above RA" category, the CAISO's Department of Market Monitoring (DMM) produced an assessment that provides greater granularity. The DMM's analysis does not change the conclusions of this Final Analysis. See Section 3.6 Resource adequacy capacity in Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

and (3) non-RA import resources.[52] The DMM indicates that there was approximately 3,000 MW and 2,500 MW available to the real-time market from RA resources bidding above their RA shown amounts during the net demand peak on August 14 and 15, respectively.[53] Nonetheless, the DMM analysis shows that bids from all RA resources made available to the real-time market on August 14 and 15, even above what was shown to the CAISO as RA capacity, were not sufficient to meet demand and WECC-required 6% operating reserve requirements during the net demand peak.[54] Note that this part of DMM's assessment does not account for RA resources that bid into the market but were not cleared, such as RA imports that were economically displaced by lower-priced imports due to transmission congestion, as discussed in more detail below. In addition, the DMM notes that day-ahead bids from RA resources, including bid quantities from RA resources above their RA showings, were not sufficient to meet the load forecast plus ancillary service requirements on August 17 and 18. In all cases, the DMM report also reflects that capacity was limited and DMM recommends that RA requirements are increased to more accurately reflect increasing risk of extreme weather events (*e.g.*, beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system RA targets).[55]

A detailed explanation on the interaction between RA capacity obligations, the day-ahead markets, real-time awards, and actual energy production dispatches can be found in Appendix B.

4.2.3.1 Natural Gas Fleet

Natural gas resources bid in about 300 MW less than the collective contribution of the gas fleet's RA requirements, though an additional 700 MW of bids came from resources that had no RA contract and RA resources that bid above the shown August RA requirements or both. The 1,000 MW difference between shown RA requirements and bid from RA resources is attributed largely to forced outages and derates due, at least in part, to the extreme heat. Plant derates (*i.e.*, a decrease in the available capacity of the resource) due to extreme temperatures are not uncommon and in fact increase with the temperature. Even though the CAISO had issued an RMO notification for

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[52] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 30.

[53] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, Figure 3.21, p. 32.

[54] Specifically, the requirements referred to here are market requirements, losses, spinning and non-spinning reserves.

[55] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 4.

August 14 through 17 that cancelled certain planned outages, there were roughly400 MW of planned outages that could not be cancelled and were not substituted. The largest planned outage had been approved for maintenance in June but had extended into peak summer months without providing replacement capacity. This outage was effectively a forced outage because the resource could not come back online even if the CAISO's RMO notification would have canceled the planned outage.

In addition to the forced outages known to the CAISO at the beginning of the day, on August 14, at 2:57 p.m., a unit with capacity of 494 MW recorded a forced outage because of plant trouble.[56] At the time it went out of service, it was generating 475 MW.

On August 15 at 6:13 p.m., a generator unexpectedly ramped down generation from about 394 MW to about 146 MW, resulting in a loss of about 248 MW.[57] This was not an outage, but a ramp down from the CAISO dispatch, which the CAISO now understands to be due to an erroneous dispatch from the scheduling coordinator to the plant.

4.2.3.2 Imports

The imports category includes both non-resource-specific resources as well as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station. Total import bids received in the day-ahead market were between 2,600 MW and 3,400 MW (40-50%) higher than the August shown RA requirements from imports. Despite this robust level of import bids, transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint. Through August, a major transmission line in the Pacific Northwest upstream from the CAISO system was forced on outage because of a storm in May 2020 that caused damage and thus derated the California Oregon Intertie (COI) into August. The derate reduced the CAISO's transfer capability by nearly 650 MW and caused congestion on usual import transmission paths across the COI and Nevada-Oregon Border (NOB).[58] In other words, more energy was available in the north than could be physically delivered, and the total import level was less than the amount the CAISO typically receives.

Because of this congestion, lower-priced non-RA imports may have cleared the market in lieu of higher-priced RA imports. Consequently, the amount of energy production

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[56] This unit was the Blythe Energy Center in Riverside County. The rotating outages were not caused by any single generator or resource type.

[57] This unit was the Panoche Energy Center in Fresno County. The rotating outages were not caused by any single generator or resource type.

[58] *See* Grizzly-Portland General Electric (PGE) Round Butte No 1 500 kV Line at: https://transmission.bpa.gov/Business/Operations/Outages/OutagesCY2020.htm

from RA imports can be lower than the level of RA imports shown to the CAISO on RA supply plans. The CAISO estimates imports required to provide energy under RA contracts collectively bid in about 330 MW less than the shown August RA values because of congestion.

Additional imports were needed in real-time to meet high loads and counter the impacts of some practices in the day-ahead market, as described below. In total, real-time imports increased by 3,000 MW and 2,000 MW on August 14 and 15, respectively, when the CAISO declared a Stage 3 Emergency. This included imports that the CAISO market and operations was able to attract including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other BAs to reduce the impact of these challenges. These real-time imports reversed most of the economic and low priority exports that cleared the day-ahead market.

4.2.3.3 Hydro

The hydro generation category includes a variety of hydro-based resource types such as run-of-river facilities, pumping loads, and pumped storage. Although the August RA values are set almost a year ahead of time, bidding reflects the capabilities of the resources for the next day. Across both days, total hydro generation bids were equivalent to the August NQC value. The portion of these bids from resources under RA contract was about 90% of the August NQC value. However, some hydro resources bid above the shown RA quantity, and real-time energy production may be higher or lower than this amount. Therefore, actual energy production from these shown RA resources was higher than the amount reported to the CAISO. Additional analysis is needed to accurately characterize the level of generation from shown RA resources above the shown capacity level.

4.2.3.4 Solar and Wind

The total solar fleet within the CAISO collectively bid into the day-ahead market about 370 MW (13%) more than the RA obligation at the net demand peak on August 14 but 160 MW (5%) less on August 15. In contrast, actual energy production during the net demand peak was 1,200 MW (40%) less and 1,000 MW (35%) less on August 14 and 15, respectively. The total wind fleet within the CAISO collectively bid into the day-ahead market about 230 MW (20%) less than the RA obligation at the net peak demand on August 14 but 120 MW (10%) more on August 15. In contrast, actual energy production during the net demand peak was 640 MW (57%) less and 230 MW (20%) less on August 14 and 15, respectively.

For solar and wind, the August resource adequacy NQC values were set based on modeled assumptions and it is normal to see variations between this amount and the bid-in amount, which reflects forecasted conditions for the following day. The largest difference between August shown values and the bids is during the net demand peak hour where the combined solar and wind NQC values decline by 1,300 MW on both days. In addition, solar generation was reduced by high clouds from a storm covering large parts of California on August 15 and smoke from active fires on both days. Wind generation was impacted by storm patterns through the peak and net demand peak period on August 15, which caused a decline in actual production of 1,200 MW between 5:12 p.m. and 6:12 p.m. before increasing again closer to 7:00 p.m.

4.2.3.5 Demand response

Current market-integrated demand response programs are designed to reduce demand when the programs are dispatched based on market needs. They take on many forms, but in the CAISO market, there are two main programs that bid into the CAISO's wholesale markets and are dispatched similar to a power plant: emergency and economic demand response.

Emergency demand response programs (reliability demand response resources or RDRR) in the CAISO market can be triggered by the CAISO after at least a Warning is declared. These programs are managed by the investor-owned utilities (IOUs) and are credited by the CPUC against the RA obligations of CPUC-jurisdictional LSEs. Economic demand response (proxy demand response or PDR) exists for IOU and CPUC-jurisdictional third-party providers (non-IOU) though IOU PDR is also credited while the non-IOU PDR is shown mostly as RA to the CAISO.

CPUC-jurisdictional LSEs' total August 2020 credits were 1,632 MW, representing 3.5% of their total obligations.[59] Of this total credit, 1,472 MW reflects IOU emergency and economic demand response programs, the vast majority of which is the RDDR emergency demand response programs that are triggered by CAISO's emergency protocols. The remainder consists of the IOUs' economically bid PDR demand response programs. Another 10 MW of credited demand response is attributed to non-IOU PDR. The non-IOU entities are CPUC-jurisdictional third parties. All credited amounts include "gross up" credits the CPUC applies to demand response resources to reflect the associated "preferred" resource status in California's loading order. These credits translate to about 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies.

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[59] Non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of the total obligations.

Although these resources are not visible on supply plans to the CAISO, the CPUC publishes the capacity values and the IOUs provide daily availability reports to the CAISO.[60] In addition to these credited resources that are not visible on supply plans, demand response that was included on the supply plans of CPUC-jurisdictional entities as RA capacity for August 2020 totaled 243 MW.

Table 4.2 below summarizes the demand response RA and credits for August and September 2020.

Table 4.2: August and September 2020 Demand Response Credits and Shown RA

August 2020	**Credited**	**Shown RA**
Reliability Demand Response Resource (RDRR)	1,115 MW – IOU	n/a
Proxy Demand Response (PDR)	358 MW – IOU 10 MW – Non-IOU	243 MW – Non-IOU
Total	**1,482 MW**	**243 MW**
September 2020		
Reliability Demand Response Resource (RDRR)	1,087 MW – IOU	n/a
Proxy Demand Response (PDR)	312 MW – IOU 10 MW – Non-IOU	237 MW – Non-IOU
Total	**1,409 MW**	**237 MW**

Note: All credited amounts include transmission and distribution loss factors and planning reserve margin gross up.

Figure 4.5 below compares the dispatch and response of credited IOU RDRR from August 14 through 18 and for September 5 and 6. These are the days during the mid-August extreme heat wave as well as the Labor Day heat wave where the CAISO declared at least a Warning. Credited RDRR in the CAISO market consists of three factors. The first is the expected load curtailment from 4 p.m. to 9 p.m. based on the CPUC's QC methodology (green dotted line). The CPUC then adds to this amount a transmission and distribution losses gross up factor (grey dashed line).[61] Lastly, the entire

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[60] *See:* "2020 IOU Demand Response Program Totals" at https://www.cpuc.ca.gov/General.aspx?id=6311

[61] See CPUC Decision15-06-063. The transmission and distribution losses gross up factors are: Pacific Gas and Electric 1.097; San Diego Gas & Electric 1.096; and Southern California Edison 1.076.

amount is scaled up by the 15% PRM (solid orange line). The graph also includes the RDRR available for dispatch at the time requested by the CAISO (blue squares) and the RDRR amounts available as reported on the daily availability reports sent to the CAISO by the IOUs (red dots). Both amounts can differ from the credited amounts. (For instance, if a facility is offline due to maintenance, it will have no load to drop.) Lastly, the figure shows the RDRR actual metered load drop (blue bars).[62] All times shown are the beginning of the hour.

Figure 4.5: Credited IOU Reliability Demand Response Resource Real-Time Availability, Dispatch, and Performance

All times shown are at the start of the hour

In addition to emergency demand response, there is economic demand response. Figure 4.6 compares the day-ahead energy bids and awards of credited IOU and non-IOU PDR for the same days and hours as the RDRR analysis for ease of comparison. Like credited RDRR, the CPUC credits all IOU PDR and some non-IOU PDR with the same transmission and distribution and 15% PRM gross up factors. Unlike RDRR, PDR does not require a CAISO trigger and is bid and dispatched in the CAISO market like a generation resource. The maximum day-ahead bids (yellow dots) are compared against the maximum day-ahead awards (blue triangles).

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[62] There is a small amount of RDRR economically bid into the day-ahead market. See Appendix B for discussion.

Figure 4.6: Credited IOU and Non-IOU Proxy Demand Response Day-Ahead Bids and Awards

Figure 4.7 compares the real-time energy awards and response of credited IOU and non-IOU PDR for the same days and hours. The maximum real-time bids (yellow dots) are compared against the maximum real-time energy awards (blue triangles). Actual response (blue bars) is determined by the meter data and baseline methodologies.[63] The actual response reflects total load drop from day-ahead and real-time awards. All times shown are the beginning of the hour.

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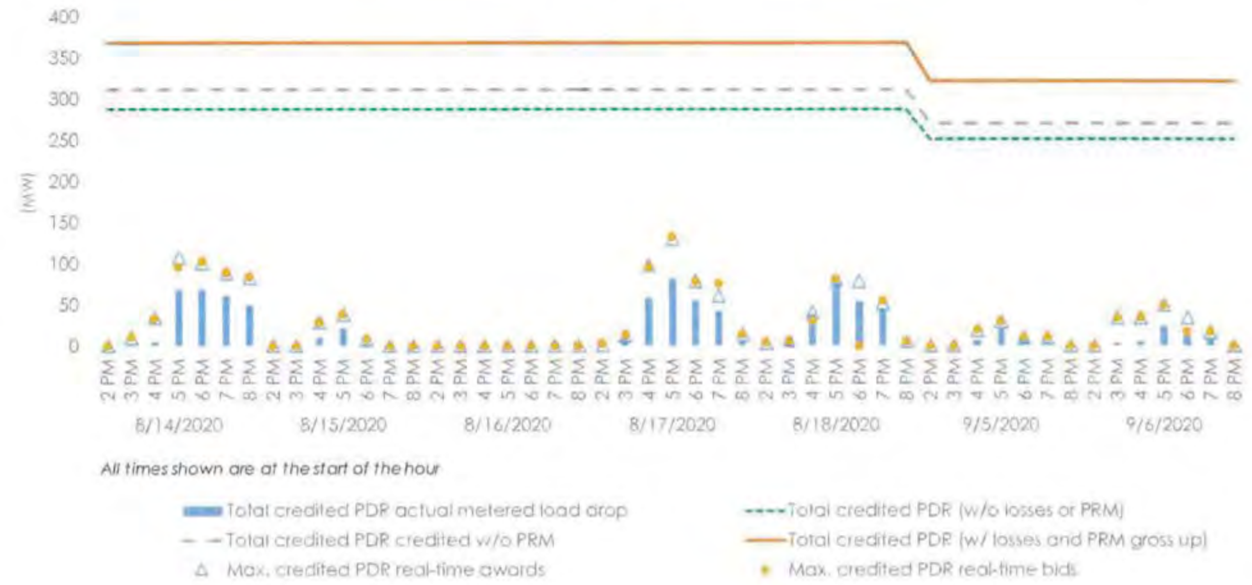
[63] See Appendix B for a discussion on baseline methodologies.

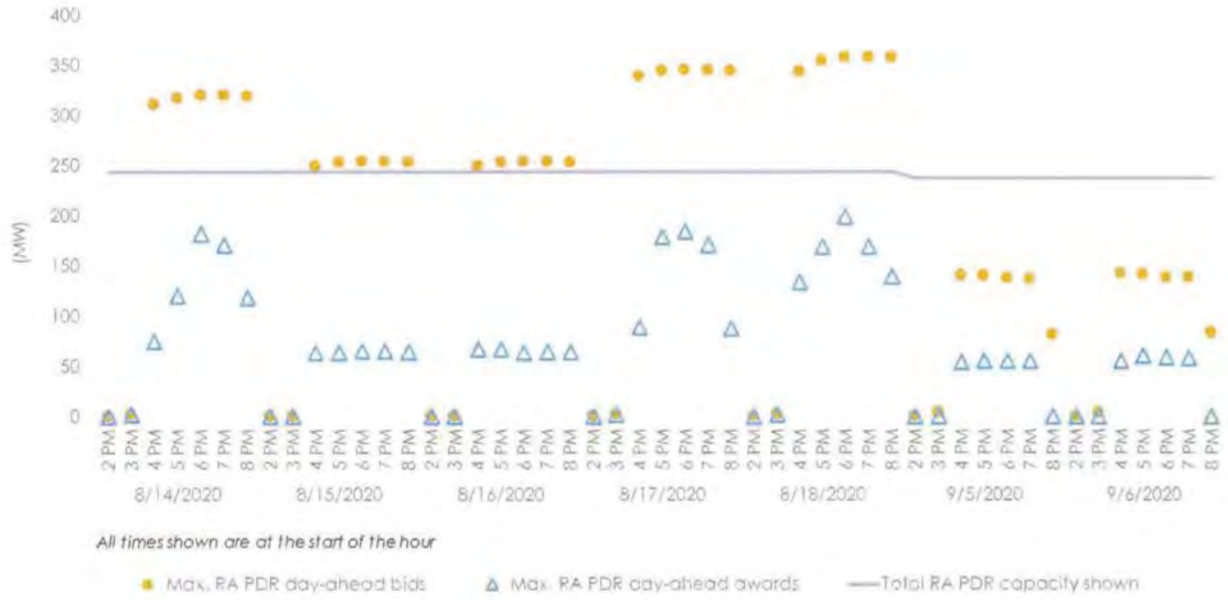
Figure 4.7: Credited IOU and Non-IOU Proxy Demand Response Real-Time Bids, Awards, and Performance



All times shown are at the start of the hour

Unlike IOU demand response, non-IOU PDR is mostly shown as RA capacity which does not have a transmission and distribution loss factor nor a 15% PRM gross up. Figure 4.8 below compares the total shown RA capacity (purple line) to the maximum day-ahead market bids (yellow dots) and awards (blue triangles). All times shown are the beginning of the hour.

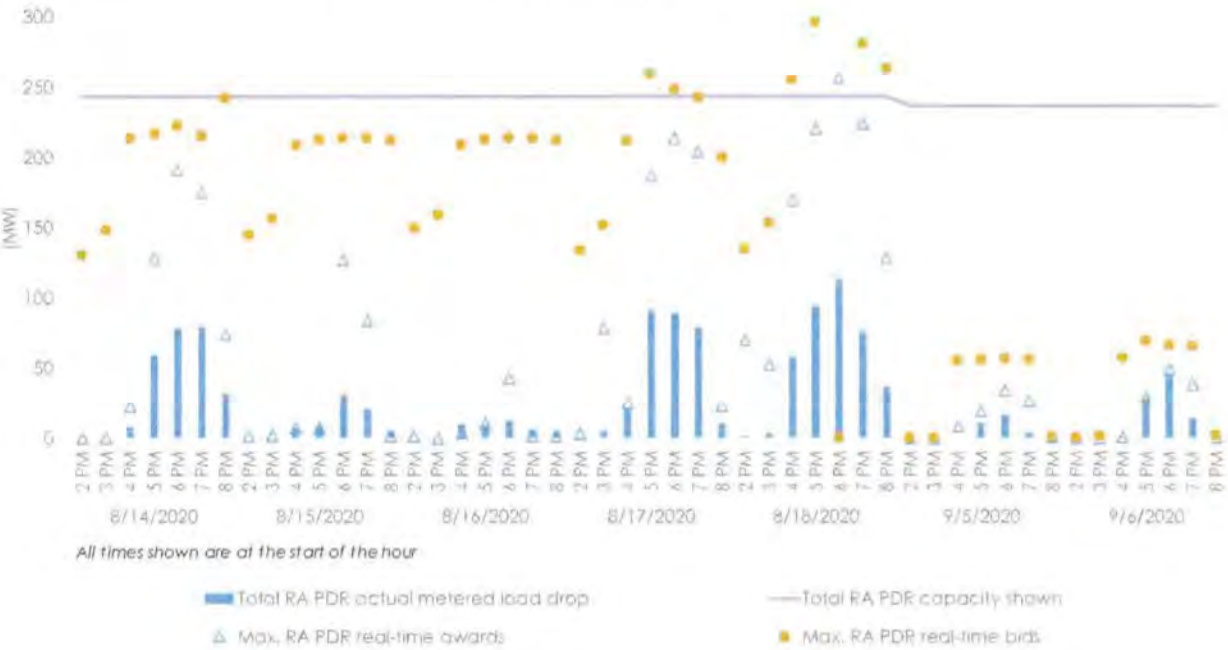
Figure 4.8: Non-IOU Proxy Demand Response Shown as RA Day-Ahead Bids and Awards



All times shown are at the start of the hour

Figure 4.9 compares the total shown RA capacity (purple line) to the maximum real-time market bids (yellow dots), awards (blue triangles), and actual metered load drop (blue bars). Actual response is determined by the meter data and the baseline methodologies discussed above. The actual response reflects total load drop from day-ahead and real-time awards. The same days and hours as the RDRR analysis are shown for ease of comparison. All times shown are the beginning of the hour.

Figure 4.9: Non-IOU Proxy Demand Response Shown as RA Real-Time Bids, Awards, and Performance



All times shown are at the start of the hour

Table 4.3 below summarizes the demand response performance during the August 14 and 15 Stage 3 events. The comparison is benchmarked against the metered load drop of each of the three categories of demand response as a percentage of the RDRR available or PDR awards and each of the three factors as applicable.

Table 4.3: Comparison of Demand Response Performance During August Stage 3 Events

During 8/14 Stage 3	Metered load drop	RDRR dispatched or PDR real-time awards	% metered load drop	Credited (w/o losses or PRM gross up) or shown RA	% metered load drop	Credited w/o PRM	% metered load drop	Credited (w/ losses and PRM gross up)	% metered load drop
IOU RDRR (credited)	762	935	81%	904	84%	978	78%	1,115	68%
PDR (credited)	69	101	68%	288	24%	311	22%	368	19%
PDR (RA)	79	191	41%	243	33%	n/a	n/a	n/a	n/a
During 8/15 Stage 3									
IOU RDRR (credited)	722	846	85%	904	80%	978	74%	1,115	65%
PDR (credited)	2	8	30%	288	1%	311	1%	368	1%
PDR (RA)	32	127	25%	243	13%	n/a	n/a	n/a	n/a

Recommendations:

1. RDRR metered load drop approached the real-time dispatch levels; however, there is still a gap between these two levels. Further study is needed to close this gap.
2. The observed divergence between the PDR available and awarded MW in the CAISO markets indicates there was unutilized RA capacity during the critical events of the August extreme heatwave. Although a part of this divergence in the real-time markets is due to some demand response resources not being capable of responding to real-time conditions, most of this divergence may be due to bidding practices of PDR providers that reduce the likelihood of the associated demand response resources being selected in the day-ahead market, even on days with extremely high day-ahead demand forecasts. Further study is needed to examine how demand response resources are contributing to grid reliability and whether changes in RA or market requirements are warranted to align with the limitations of some demand response resources.
3. The observed divergence between awarded MW and delivered MW (load drop) requires further study and remedy. The divergence is particularly large for non-IOU PDR and suggests that a significant portion of non-IOU demand response providers may not be accurately estimating available capacity.
4. The observed deviance in the aggregate PDR bidding levels relative to the must-offer obligation based on the shown RA levels on some days (both the excess and shortfall conditions) needs further study and remedy. In particular, most PDR resources are under the 1 MW RA penalty threshold. The CAISO may assess a penalty if RA capacity is not bid into the CAISO market as required.
5. The CPUC applies "gross up" credits to demand response resources to reflect about 10% in transmission and distribution losses that demand-side resources avoid, and 15% for avoided planning reserve margin procurement for customers

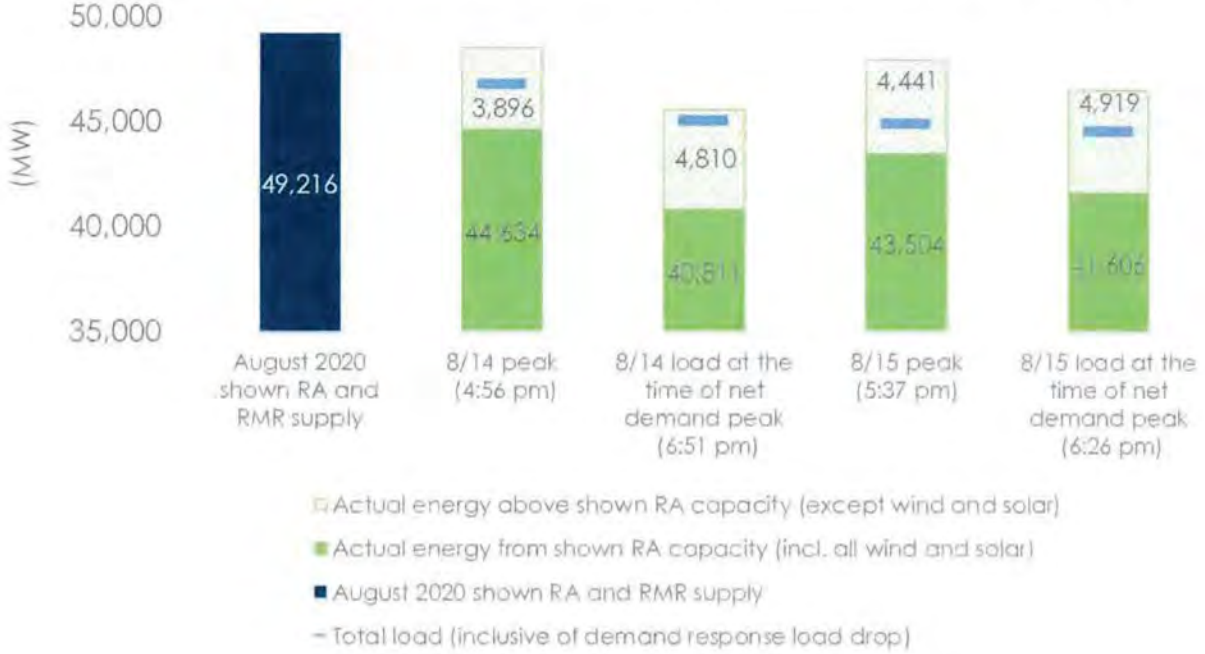
who agree to drop load in grid emergencies. This results in a gap between customer-metered load drop and expected load drop based on the amount credited against RA requirements. The CAISO's BPM appeals process is attempting to address this issue constructively and collaboratively with stakeholders.

4.2.3.6 Combined Resources

Overall, the largest gap between demand and generation from the RA fleet plus resources under an RMR contract occurred during the net demand peak on August 14 and 15. Based on further analysis by the DMM, the actual production of all resources shown as RA or obligated under an RMR contract was sufficient during the peak but insufficient during the net demand peak period to meet all load, losses and spinning and non-spinning reserve obligations on August 14 and 15. Figure 4.10 below compares the total August 2020 RA and RMR capacity versus actual energy production for both days during the peak and net demand peak times. The August 2020 RA capacity reflects the net qualifying capacity value shown to the CAISO on RA supply plans. For example, solar resources are valued based on the effective load carrying capability (ELCC) methodology and may produce more or less energy throughout the day. The second through fourth columns in the figure show the actual energy production from RA resources and energy produced above the shown RA capacity.

As noted above, this may undercount the amount of generation from imports and hydro resources in particular that may be shown for RA but generating above the shown capacity level or providing ancillary services. Although this is also true for solar and wind, as a conservative simplifying assumption for the analysis in Figure 4.10, all solar and wind resource generation in the CAISO footprint is categorized as RA though that has not been validated. Any IOU emergency and economic demand response dispatched during these periods is already reflected in the reduced load. The figure shows a decrease in RA-based generation between the peak and net demand peak periods. The load markers show that a portion of load was served by energy produced above the shown RA amount for each period. Also for simplicity, the figure does not include ancillary services awards.

Figure 4.10: August 2020 Shown RA and RMR Allocation vs. August 14 and 15 Actual Energy Production (Assumes All Wind and Solar Counts as RA Capacity)



Since the Preliminary Analysis was published, a review of resource performance showed that no single generator or resource type led to the rotating outages. However, there are several changes being considered to enhance resource performance:

- Natural gas – Under very high temperatures, ambient derates are not uncommon for the natural gas fleet, and high temperatures reduce the efficiency of these resources. The CEC hosted a workshop to explore potential technology options for increasing the efficiency and flexibility of the existing natural gas power plant fleet to help meet near-term electric system reliability and the longer-term transition to renewable and zero-carbon resources.[64] Subsequently, the CPUC issued a ruling intended to get the most out the existing gas fleet in its recently opened procurement rulemaking focused on summer

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[64] See: https://www.energy.ca.gov/event/workshop/2020-12/morning-session-technology-improvements-and-process-modifications-lead and https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop

2021 resources.[65] All reasonable efforts should be made to increase the efficiency of the existing fleet.

- Imports – In total, import bids received in the day-ahead market were between 40 to 50% higher than imports under RA obligations, which indicates that the CAISO was relying on imports that did not have a contract based obligation to serve demand. In addition to the rule changes the CPUC made to the RA program with regard to imports for RA year 2021, the CPUC may consider additional changes to current import requirements.
- Hydro and pumped storage – RA hydro resources provided above their RA amounts and various hydro resources across the state managed their pumping and usage schedules to improve grid reliability. There should be increased coordination by communicating as early as possible the need for additional energy or active pump management ahead of stressed grid conditions and leverage existing plans for efficiency upgrades to improve electric reliability.
- Solar and wind – The CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour. Improvements to the RA program should account for time-dependent capabilities of intermittent resources.
- Demand response – While a significant portion of emergency demand response programs (reliability demand response resources or RDRR) provided load reductions when emergencies were called, the total amount did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO. Some, but not all of this difference, is the result of the credited amounts including a "gross up" that the CPUC applies to demand response resources consisting of approximately 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies. Additional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-ahead and real-time markets, and performance of dispatched demand response.
- Battery storage – During the mid-August events and in early September there were approximately 200 MW of RA battery storage resources in the CAISO

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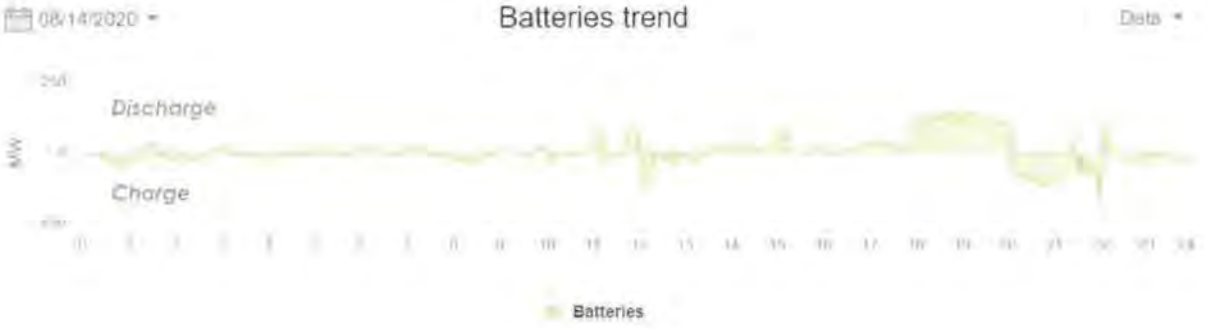
[65] CPUC, R.20-11-003, December 11, 2020 Ruling.

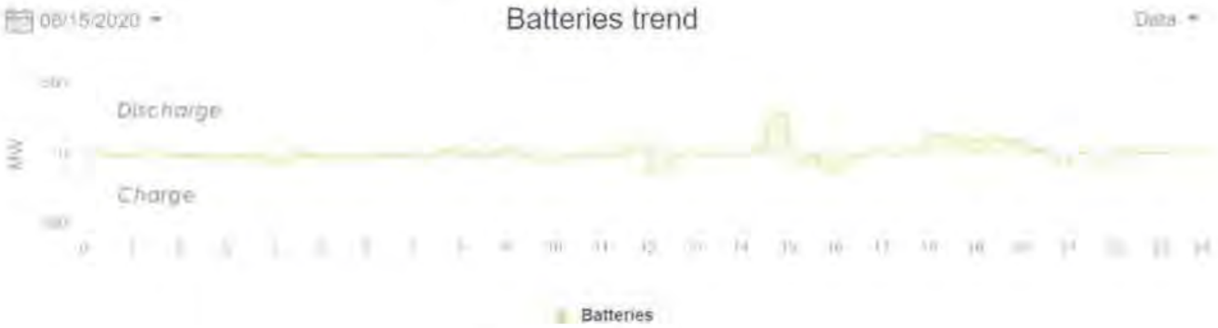
market. The Figure 4.11 and Figure 4.12 below provide illustrative snapshots of all battery performance in the CAISO market during August 14 and 15, respectively.

Figure 4.11: August 14 Illustrative Battery Storage Performance



Source: CAISO

Figure 4.12: August 15 Illustrative Battery Storage Performance



Source: CAISO

It is difficult to draw specific conclusions about fleet performance from such a small sample. The CAISO will continue to track and understand the collective behavior of the battery storage fleet and work with storage providers to effectively incentivize and align storage charge and discharge behavior with the reliability needs of the system. The CAISO has been working to develop enhancements to ensure that as the battery storage fleet size grows the CAISO market can effectively manage them. Several of these changes will only take effect fall 2021. In the interim, the CAISO will ensure storage resource providers understand how the CAISO expects to operate the system so that storage is available when needed to meet net peak demand challenges under stressed summer conditions.

4.3 Some Practices in the Day-Ahead Energy Market Exacerbated the Supply Challenges Under Highly Stressed Conditions

Energy market practices encompass inputs into the energy market, how the energy market matched supply with demand, and ultimately whether the schedules from the market fully prepared the CAISO Operational staff to run the grid. Energy market practices contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by scheduling coordinators, convergence bidding masking the tight supply conditions, and the configuration of the residual unit commitment market process.

4.3.1 Demand Should Be Appropriately Scheduled in the Day-Ahead Time frame

Scheduling coordinators representing LSEs collectively under-scheduled their demand for energy by 2,164 MW and 2,023 MW below the actual peak demand for August 14 and 15, respectively as shown in Table 4.4 below. During the net demand peak time, the under-scheduling was 1,272 MW and 1,547 MW for August 14 and 15, respectively. Under-scheduled load by scheduling coordinators limited the ability of the day-ahead market to secure sufficient supply to meet actual demand. Consequently, more exports were scheduled in the day-ahead market than were supportable from internal resources.

Table 4.4: Comparison of Under- and Over-Scheduling of Load on August 14 and 15 (Under-Scheduling Reflected as Negative Number)

	IOU	CCA	ESP	Non-CPUC	Other	Total
8/14 (MW)						
Peak	(1,288)	(153)	(206)	(131)	(385)	(2,164)
Net demand peak	(664)	(146)	8	(134)	(336)	(1,272)
8/15 (MW)						
Peak	(1,147)	(297)	(90)	(223)	(266)	(2,023)
Net demand peak	(671)	(282)	(118)	(242)	(234)	(1,547)
8/14 (%)						
Peak	(5%)	(4%)	(4%)	(3%)	(8%)	(5%)
Net demand peak	(3%)	(4%)	0%	(3%)	(7%)	(3%)
8/15 (%)						
Peak	(4%)	(8%)	(2%)	(6%)	(6%)	(5%)
Net demand peak	(3%)	(8%)	(2%)	(6%)	(5%)	(4%)

The CAISO surveyed scheduling coordinators representing 75% of the peak load in the CAISO footprint, including the three large IOUs, to better understand the drivers behind the under-scheduling. Load serving entities reported that their primary goal was to develop the most accurate forecast possible to bid into the CAISO's day-ahead market. However, they reported several challenges in meeting this goal that included: data quality and availability, extreme weather conditions, COVID-19 and shelter-in-place impacts, and changes in the entities serving load within the IOU footprints.

4.3.2 Convergence Bidding Masked Tight Supply Conditions

Convergence bids are non-physical positions taken in the day-ahead market and liquidated in real-time for converging prices between the day-ahead and real-time markets that would otherwise not be achievable with only physical bids. Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in aligning loads and resources for the next day. However, during August 14 and 15, the under-scheduling of load and the fact that the bulk of the convergence bids clearing the day ahead market were financial supply positions and not demand positions created the ability for the day-ahead market to clear more exports than were ultimately physically supportable. After observing this interaction in the day-ahead market, to ensure the CAISO could contiunue to manage the system reliabily, on August 16 the CAISO temporarly suspended convergence bidding for trade days August 18 through August 21. The CAISO reinstated convergence bidding after demand conditions no longer appeared to pose the same risk in the day-ahead market. Although under its tariff the CAISO continues to have the authority to suspend convergence bidding when it threatens its ability to manage the system reliabily, the CAISO anticipates its efforts to promote more accurate day-ahead load schedules and changes to its management of export schedules will diminish the need to suspend convergence bidding.

4.3.3 Residual Unit Commitment Process Changes Were Needed

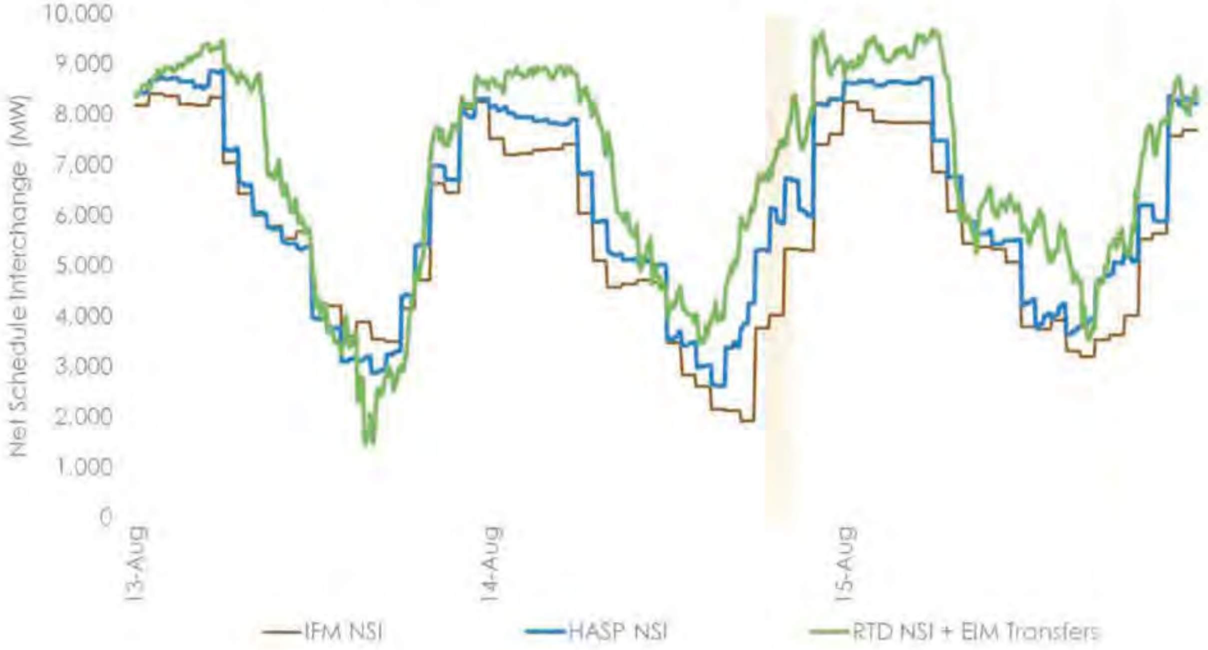
The residual unit commitment (RUC) process is part of the CAISO's day-ahead market. The RUC provides additional reliability checks based on the CAISO's forecast of CAISO load after it has cleared the integrated forward market, which is based on schedules and bids for supply and demand.

After reviewing the perfomance of the day-ahead market for August 14, the CAISO determined that a market enhancement that was made to the RUC process in prior years was masking the effects of load under-scheduling and convergence bidding. This enhancement provides necessary functionality for other market processes, but in the RUC process it erroneously signaled that more exports were physically supportable than actually were.

The CAISO modified the RUC process to correct for this issue starting with the day-ahead market for September 5, 2020, and this modification has since allowed CAISO to conduct its reliability check appropriately. This ensures that exports that are not physically feasible in the day-ahead are appropriately reduced in the RUC process. In addition, the CAISO modified the real-time market inputs priorities so that only those exports found to be physically feasible in RUC are given a high priority in the real-time market rather than those cleared in the integrated forward market. The CAISO also initiated a stakeholder process to consider additonal necessary changes to its management of export schedules.

Although the issue with the RUC process was problematic, the CAISO's real-time market and operations helped significantly reduce the combined effects of load under-scheduling, convergence bidding and the RUC issue described above. The CAISO relied on the real-time market and operations to attract more imports including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other BAs. Figure 4.13 below compares the net imports in the day-ahead (shown as the integrated forward market or IFM) with the real-time net imports provided during the hour-ahead scheduling process (HASP) and the real-time dispatch (RTD) net scheduled interchange (NSI) plus transfers from the Energy Imbalance Market (EIM). In total, real-time imports increased by 3,000 MW and 2,000 MW on August 14 and 15, respectively, when the CAISO declared a Stage 3.

Figure 4.13: Net Imports During August 13-15



However actual supply and demand conditions continued to diverge from market and emergency plans such that even with the additional real-time imports, the CAISO could not maintain required operating reserves as the net load peak approached on August 14 and 15. Though fewer exports may have been scheduled in the day-ahead market had the these market issues not existed, it is possilble that the export reductions to other balancing authority areas would have resulted in reduced imports and assistance in the real-time. Therefore, it is unknown whether the export reductions would have prevented load shedding.

5 Actions Taken During August 16 Through 19 to Mitigate Projected Supply Shortfalls

Although August 14 and August 15 are the primary focus due to the rotating outages that occurred during those days, August 16 through 19 were projected to have much higher supply shortfall. If not for the leadership through the Governor's Office to mobilize a statewide effort to address the situation, California might have experienced further rotating outages in August due to the unprecedented multi-day extreme heat wave across the West.

In preparing for continued challenging conditions on Monday, August 17, the CPUC and CEC worked closely with the Governor's Office to take immediate actions designed to reduce load or increase generating capacity within the state or both. The actions were taken with the goal of balancing factors such as the degree to which the action would help address the deficit, the durability of the action over the week, the level of disruption to commercial and residential customers, impacts on air quality and water, and the potential for disproportionate effects on disadvantaged communities.

On August 16, Governor Newsom declared a State of Emergency[66], and on August 17 he signed Executive Order N-74-20,[67] which allowed temporarily easing of regulations on stationary generators, portable generators, and auxiliary engines by vessels berthed in California ports. This proclamation enhanced the response of the Governor's Office, CAISO, CEC, and CPUC as they worked collectively to create a statewide mobilization to:

- Conserve electricity
- Reduce demand on the grid by:
    - Moving onsite demand to backup / behind-the-meter generation
    - Deploying demand response programs
    - Initiating demand flexibility
- Increase access to supply-side resources by:
    - Maximization of output from generation resources
    - Additional procurement of resources

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[66] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation-text.pdf

[67] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf

  - Resource support from other balancing areas

The efforts led to estimated reductions in peak demand on Monday (August 17) and Tuesday (August 18) by nearly 4,000 MW and added nearly 950 MW of available temporary generation to balance the grid. Table 5.1 below shows the difference between day-ahead forecasted peak and the actual peak, which was largely realized due to the statewide efforts and includes the impacts of activated demand response programs.

Table 5.1: Day-Ahead Peak Forecast vs. Actual Peak During Heat Event (Updated)

	Day-Ahead Peak forecast (MW)	Actual Peak (MW)	Difference (MW)
8/14/2020	46,257	46,802	545
8/15/2020	45,514	44,957	(557)
8/16/2020	44,395	43,816	(579)
8/17/2020	49,824	45,169	(4,655)
8/18/2020	50,485	47,120	(3,365)
8/19/2020	47,382	46,074	(1,308)
9/4/2020	41,009	40,674	(335)
9/5/2020	45,231	46,272	1,041
9/6/2020	49,166	46,887	(2,279)
9/7/2020	45,797	41,774	(4,023)

5.1 Detailed Description of Actions Taken

5.1.1 Awareness Campaign and Appeal for Conservation

- The CAISO continued to issue Flex Alerts and warnings.
- The CAISO, CEC, and CPUC supported the Governor's Office and the California Governor's Office of Emergency Services to publicly request electricity customers lower energy use during the most critical time of the day, 3 p.m. to 10 p.m.
- The CPUC issued a letter to the investor-owned utilities on August 16 requesting that they aggressively pursue conservation messaging and advertising, and requested Community Choice Aggregators do the same.
- The CPUC redirected the Energy Upgrade California® marketing campaign messaging and media outreach to focus on conservation messaging.

- The CEC, CPUC, and Governor's Office used a wide variety of media to ensure widespread awareness, including freeway signage, social media, website and app updates.

5.1.2 Demand Reduction Actions

Demand reduction efforts included transferring demand from the grid to on-site sources, deploying demand response programs, and initiating demand flexibility.

Transfer of Demand from Grid to On-site Sources

- The CAISO and CEC coordinated with data center customers of Silicon Valley Power to move nearly 100 MW of load to onsite backup generation facilities.
- The CEC coordinated with the U.S. Navy and Marine Corps to disconnect 22 ships from shore power, move a submarine base to backup generators, and activate several microgrid facilities, resulting in about 23.5 MW of load reduction.
- The CEC coordinated with six Electric Program Investment Charge-funded microgrids to reduce load by about 1.2 MW each day.

Deployment of Demand Response Programs

- On August 17, the CPUC issued a letter clarifying the use of back-up generators in connection with specific demand response programs is allowable, which resulted in at least 50 MW of additional demand reduction each day.
- "The Los Angeles Department of Water and Power (LADWP) on Aug. 13 said that in addition to asking residential customers to save energy, LADWP was also implementing a Demand Response event with its commercial customers in response to a CAISO Flex Alert. The alert asked all power customers to save energy from 3:00 p.m. to 10:00 p.m. on Friday, August 14."[68]

Initiation of Demand Flexibility

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[68] American Public Power Association. "Calif. grid operator initiates rotating power outages with extreme heat, high power demand," August 17, 2020. https://www.publicpower.org/periodical/article/calif-grid-operator-initiates-rotating-power-outages-with-extreme-heat-high

- DWR and the U.S. Bureau of Reclamation shifted on-peak pumping load that resulted in 72 MW of load flexibility.
- The CEC contacted Tesla, which offered to reduce load at its factory between 3 p.m. and 8 p.m.
- The Governor's Office contacted large industrial users to seek opportunities for load shifting away from peak hours. In response, Poseidon Water Desal Plant reduced its load by 24 MW; Dole Foods reduced its load by 3.3 MW, with support from SDG&E; California Steel Industries reduced its load by 35 MW on Monday through Wednesday (August 17 through 19) from of 3 p.m. to 8 p.m.; and California Resources Corporation reduced its demand by about 100 MW during peak hours, shutting in 7% of oil production daily for six-hour peak periods.

5.1.3 Increase Access to Supply-Side Resources

Actions taken to increase access to supply-side resources included maximized output from generation resources, additional procurement of resources, and resource support from neighboring BAs.

Maximization of Output from Generation Resources

- The CEC led the effort for jurisdictional power plants to contribute an additional 147 MW of generation (60 MW from SEGS Solar Plant, 42 MW from Ivanpah Solar Power Plant, and 45 MW from the CPV Sentinel Energy Project.)
- The CEC contacted Watson Cogen and received a commitment for it to provide 20 to 30 MW of additional generation August 17 and 18.
- The Governor's Office secured commitments from three refineries to increase their on-site generators. El Segundo Refinery cogeneration unit ramped up to export 10 MW to the grid. Richmond Refinery increased its onsite power production by 4 MW to reduce its imports. Bakersfield Refinery generated 22 MW for export to the grid for one day.
- The CEC worked with the City and County of San Francisco to maximize power output at Hetch Hetchy, which allowed an additional 150 MW of generation during the peak load.
- DWR and the Metropolitan Water District (MWD) adjusted water operations to shift 80 MW of electricity generation to the peak period.
- PG&E deployed temporary generation (procured for Public Safety Power Shutoff purposes) across its service territory, totaling about 60 MW.

- SCE worked with generators to ensure that additional capacity was made available to the system from facilities with gas on site or through inverter changes.

Resource Support from Neighboring BAs

- LADWP helped bring additional generation from Haynes Unit 1 and Scattergood natural gas-fired plants, totaling 300 to 600 MW.
- SMUD issued a news release on August 16, calling for conservation.[69]
- The Western Area Power Administration (WAPA) offered 40 MW of its Hoover Dam allocation.

5.1.4 CAISO Market Actions

Before August 14, the CAISO had already begun to exceptionally dispatch long start units to ensure they would be available to provide energy. The CAISO exceptionally dispatched RA and non-RA resources. As explained in Section 2, non-RA capacity is eligible for capacity payment under the CAISO's capacity procurement mechanism (CPM) authorization in return for a commitment to provide energy to the CAISO for at least 30 days. However, no resources accepted such an offer because of prior contracting commitments to other BAs. However, many provided short-term energy as requested. Starting August 16, the CAISO succeeded in attracting non-RA capacity under the CPM authorization due to a system capacity shortage caused by the extreme heat wave. In total, 477.45 MW of CPM capacity was procured.[70]

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[69] American Public Power Association. "Calif. grid operator initiates rotating power outages with extreme heat, high power demand," August 17, 2020, https://www.publicpower.org/periodical/article/calif-grid-operator-initiates-rotating-power-outages-with-extreme-heat-high

[70] See http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation-081620.html; http://www.caiso.com/Documents/SignificantEventCapacityProcurementMechanismDesignation-081720-081820.html; http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation-081720.html; http://www.caiso.com/Documents/SignificantEventCapacityProcurementMechanismDesignation-081920.html; and http://www.caiso.com/Documents/RevisedSignificantEventCapacityProcurementMechanismDesignation-081720-081820.html

6 Recommendations

This section identifies a set of recommendations and immediate steps that either have been or are being implemented or are recommended to reduce the likelihood of additional rotating outages during the remainder of this year or next year. The recommendations are organized into three time frames: Near-term (2021), Mid-term (2022-25) and Longer-term (beyond 2025). Within each time frame, the recommendations are grouped into categories to specifically address the contributing factors established in Section 4 and systematize and expand on the mitigation activities undertaken to address the potential shortfall on August 16 through 19 as detailed in Section 5.

1) Near-term – by Summer 2021

a) Current actions to prepare for Summer 2021

i) The CPUC opened an Emergency Reliability rulemaking (R.20-11-003) to procure additional resources to meet California's electricity demand in summer 2021. Through this proceeding, the CPUC has already directed the state's three large investor-owned utilities to seek contracts for additional supply-side capacity and has requested proposals for additional demand-side resources that can be available during the net demand peak period (i.e., the hours past the gross peak when solar production is very low or zero) for summer 2021 and summer 2022. The CPUC and parties to the proceeding, including the CAISO, will continue to evaluate proposals and procurement targets for both supply-side and demand-side resources.

ii) The CAISO is continuing to perform analysis supporting an increase to the CPUC's RA program procurement targets. Based on the analysis to date, the CAISO recommends that the targets apply to both the gross peak and the critical hour of the net demand peak period during the months of June through October 2021.

iii) The CAISO is expediting a stakeholder process to consider market rule and practice changes by June 2021 that will ensure the CAISO's market mechanisms accurately reflect the actual balance of supply and demand during stressed operating conditions. This initiative will consider changes that incentivize accurate scheduling in the day-ahead market, appropriate prioritization of export schedules, and evaluate performance incentives and penalties for the RA fleet. The CAISO is also working with stakeholders to ensure the efficient and reliable operation of battery storage resources given the significant amount of new storage that will be on the system next summer and beyond. Through a stakeholder process, the CAISO will pursue changes to its planned outage rules.

iv) The CPUC is tracking progress on generation and battery storage projects that are currently under construction in California to ensure there are no CPUC-related regulatory barriers that would prevent them from being completed by their targeted online dates. The CAISO will continue to work with developers to address interconnection issues as they arise.

v) The CAISO and CEC will coordinate with non-CPUC-jurisdictional entities to encourage additional necessary procurement by such entities.

vi) The CEC is conducting probabilistic studies that evaluate the loss of load expectation on the California system to determine the amount of capacity that needs to be installed to meet the desired service reliability targets.

vii) The CAISO, CPUC, and CEC are planning to enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand side efforts during extreme heat events.

viii) Preparations by the CAISO, CPUC, and CEC are underway to improve advance coordination for contingencies, including communication protocols and development of a contingency plan. The contingency plan will draw from actions taken statewide under the leadership of the Governor's Office to mitigate the anticipated shortfall from August 17 through 19, 2020.

b) Resource Planning and Procurement

i) **RA crediting counting requirements** - The CAISO to continue efforts to stipulate its expectations on credits applied by CPUC and non-CPUC jurisdictional entities.

c) Market Enhancements

Based on this Final Analysis, the CAISO has identified possible improvements to its market practices to ensure they accurately reflect the actual balance of supply and demand during stressed operating conditions. Furthermore, market practices should ensure sufficient resources are available to serve load across all hours, including the peak and net demand peak.

i) **Address under-scheduled CAISO load in the day-ahead market** – The CAISO, working with stakeholders, to develop and institute a procedure to adequately communicate to the market (including LSEs and their scheduling coordinators) the need to schedule load in the day-ahead market by:

(1) Continuing its new practice of notifying the market of the degree of under-scheduled load based on prior day results of the day-ahead

market if load is under-scheduled, and request that LSE scheduling coordinators properly schedule their anticipated load in the day-ahead market[71];

(2) Increasing outreach to LSEs to discuss and resolve any issues with their ability to schedule the amount of load in the day-ahead market consistent with system conditions;

ii) **Improve load scheduling accuracy** - CPUC to explore what technical solutions are needed to allow its jurisdictional utility distribution companies to provide customer usage data to CCAs and ESPs more frequently to improve load scheduling accuracy.

iii) **CAISO to pursue the following market rule enhancements through its stakeholder processes:**

(1) Through a stakeholder process, pursue changes to CAISO RA market rules to ensure planned outages do not create unnecessary reliability risk and that performance penalties are sufficient to ensure compliance.

(2) Working with stakeholders, develop a process to evaluate monthly RA supply plans with backstop, if necessary.

(3) In coordination with the CPUC, continue to work with stakeholders to clarify and refine the counting rules as they apply to hydro resources, demand response resources, renewable, use limited resources, and imports.

(4) Through a stakeholder process, continue to enhance the day-ahead market design to ensure reliable load and supply scheduling.

(5) Through a stakeholder process, prioritize market enhancements to ensure existing and new resources are effective in addressing grid needs. For storage and storage hybrid resources, the CAISO will work with and communicate to these resource operators expected charge and discharge behavior to align with grid needs.

(6) Through a stakeholder process, evaluate performance incentives and penalties for the RA fleet.

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[71] http://www.caiso.com/Documents/CaliforniaISOMarketParticipantsHeatWavePreparation-LoadScheduling.html

d) Improving Situational Awareness and Planning for Contingencies

i) **State-Wide and WECC-Wide Resource Sufficiency Assessments** – The CEC, in coordination with CPUC, CAISO, and other BAAs, will begin developing a statewide summer assessment to provide additional information to support RA proceedings beginning in 2021. The CEC will also engage in relevant WECC RA processes to maintain situational awareness of the WECC-wide summer assessments and publish information as appropriate.

ii) **Develop Communication Protocols to Trigger Statewide Coordination** - The CAISO, CEC, and CPUC will develop improved warning and trigger protocols to adequately forewarn the severity of an extreme event and initiate coordination with one another, with other State agencies and the Governor's Office, with the IOUs, municipal or POUs, and the CCAs.

iii) **Contingency Plan** – The CEC, in coordination with the Governor's Office, CPUC, CAISO, and other appropriate state agencies and stakeholders, will systematize a Contingency Plan. This plan will draw from actions taken statewide under the leadership of the Governor's Office to address the anticipated shortfall from August 17 through 19. It will be ready to be deployed in case of unanticipated stressed conditions. The Contingency Plan will lay out a process to sequence emergency measures in rank order to minimize environmental, equity, and safety impacts. The measures will include requesting load flexibility and conservation from large users, moving demand to microgrids and back-up generation (including emergency use of diesel generation that the three large electric IOUs own or have under contract for use in major emergencies such as wildfire prevention and wildfire or earthquake response), and temporarily increasing capacity of existing generation resources.

2) Mid-Term (2022 through 2025) and Long-Term

a) Resource Planning and Development

i) **Consider New Resources -** Consider whether new resources are needed to meet the mid- and longer-term time frames reflective of the re-evaluation of the forecast basis and PRM noted above. Conduct a production cost analysis to ensure that additional resources will meet reliability needs during all hours of the year, including the net demand period.

ii) Accelerate Deployment of Demand Side Resources

(1) **Dynamic Rates –** Rate design can help reduce demand at net demand peak by creating financial incentives to shift demand to other times of the day. The CPUC is already implementing rate design changes by directing

the three large IOUs in California to default all residential customers to time-of-use rates (TOU).[72] SDG&E has already defaulted most of its customers to TOU rates. PG&E and SCE will begin moving their customers to TOU plans in 2021.

(2) **Load management standards and SB 49** - Beyond the move to TOU rates, other dynamic rate designs that more accurately reflect real-time market conditions (or GHG emissions) can be developed. These rate plans can be paired with low-cost hardware to enable automated demand flexibility. The CEC has already opened a proceeding on Load Management Standards (LMS) to 1) require the large electric utilities and CCAs to post their time-based rates in a public database in a standardized format, and 2) automate the publishing of those rates in real-time in machine-readable form. The CEC is also beginning to implement the load flexibility requirements laid out in Senate Bill (SB) 49 (Skinner, Chapter 697, Statutes of 2019) in conjunction with the State Water Resources Control Board. The CPUC and CEC should open additional proceedings to expand dynamic rate plans and encourage the roll out of automated devices. The CPUC and CEC will need to coordinate with the smaller non-CPUC-jurisdictional entities and CCAs to encourage these entities to implement similar rate plans and automate access to them.

iii) **Other resource-specific planning improvements** – Implement the relevant planning and development improvements identified in and/or suggested by the assessment in Section 4 of how different resource types performed during the extreme heat wave.

iv) **SB 100 scenarios** - Building on the Senate Bill (SB) 100 (De León, Chapter 312, Statutes of 2018) scenarios, consider where diverse resources can be built and the transmission and land use considerations that must considered. Establish a transmission technical working group (CAISO, BAs, CEC, CPUC) to evaluate the transmission options and constraints from the SB 100 scenarios.

b) **Market Enhancements**

i) **CAISO market enhancements** - The CAISO to continue engagement with stakeholders to develop market enhancements identified in the near-term.

ii) **Resource-specific operational improvements** – Implement the relevant operational improvements identified in and/or suggested by the assessment

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[72] Most commercial and industrial customers are already on mandatory TOU rate plans.

in Section 4 of how different resource types performed during the extreme heat wave.

c) **Improving Situational Awareness and Plan for Contingencies**

   i) **Statewide and WECC-Wide RA Assessments as Part of IEPR** - Building on the statutory role of the CEC in reviewing POU IRPs, the CEC, in coordination with CPUC, CAISO, and statewide LSEs, will develop necessary assessments as part of the *Integrated Energy Policy Report (IEPR)* to develop statewide, and WECC-wide RA assessments.

   ii) **As part of the IEPR, continue expanding assessments to support mid- to long-term planning goals by including the following:**

      (1) The CEC, CPUC, and CAISO continue mid-term efforts from SB 100, IRP, and the CAISO's transmission planning process to address electric sector reliability and resiliency considering evolving policy goals of the state. May coordinate with the California Air Resources Board.

      (2) Update (likely broaden) the range of climate scenarios to be considered in CEC forecasting (supply and demand).

      (3) Consider developing formal crosswalks between the CEC forecast and emerging SB 100 scenarios to bridge gaps between planning considerations across various planning horizons.

To ensure transparency and public engagement, more information can be found and will be updated at:

http://www.caiso.com/about/Pages/News/SummerReadiness.aspx
https://www.cpuc.ca.gov/summerreadiness/

The CAISO is also holding monthly stakeholder meetings to discuss progress towards ensuring its readiness for next summer's high heat events.

Appendix A: CEC Load Forecasts for Summer 2020

The following is a detailed discussion on the CEC's load forecast adjustment for June through September 2020. Table A.1 shows the allocation of the CEC forecast by jurisdiction type, and how those forecasts compare with both final year-ahead and month-ahead forecasts. Each element is discussed below.

Table A.1: Summary of 2020 LSE RA Forecasts

		Jun-20	Jul-20	Aug-20	Sep-20
1. 2018 IEPR Update 2020 CAISO Coincident Peak		41,220	44,650	44,955	45,277
	Adjustment for CPUC load-modifying demand response	(97)	(116)	(127)	(133)
	Adjusted CAISO Forecast	41,123	44,533	44,828	45,144
2. Disaggregation to Jurisdiction Type					
	CPUC Jurisdictional	37,138	40,170	40,495	40,779
	Non-CPUC Jurisdictional	3,984	4,363	4,333	4,365
	Adjusted CAISO Forecast	41,123	44,533	44,828	45,144
3. CPUC Reference Forecast		37,138	40,170	40,495	40,779
	Reference @ 99%	36,767	39,768	40,090	40,371
4. Final 2020 Year-Ahead Forecasts					
	CPUC Jurisdictional	36,766	40,036	40,415	40,371
	Non-CPUC Jurisdictional	3,623	3,980	4,022	3,948
	Total Forecast for Year-Ahead Showing	40,389	44,016	44,437	44,319
	Percent of Adjusted CAISO Forecast	98.2%	98.8%	99.1%	98.2%
5. June-August 2020 Month-Ahead Forecasts					
	CPUC Jurisdictional	36,914	40,132	40,571	40,758
	Non-CPUC Jurisdictional	3,782	4,086	4,169	4,041
	Total Forecast for August Month-Ahead Showing	40,696	44,218	44,741	44,798
	Percent of Adjusted CAISO Forecast	99.0%	99.3%	99.8%	99.2%

1. CEC adjusts the forecast for expected impacts of certain CPUC demand response programs, primarily critical peak pricing, which are not accounted for in the CEC

forecast but which CPUC determines may receive credit for reducing peak demand. CPUC provides the estimated load impacts.

2. CEC disaggregates the TAC area monthly peaks for PG&E and SCE to jurisdiction type. This is done using TAC area annual forecast peaks from CEC Form 1.5b, analysis of 2019 hourly loads for all individual LSEs and for the IOU service area, and preliminary forecasts submitted by LSEs in May. The JASC was briefed on the methodology and results for 2020 on June 4, 2019. For comparison, the load of the non-CPUC jurisdictional entities at the time of the 2019 system peak for POUs was 4,393 MW, and 2019 RA obligation for those POUs was 4,285 MW.

3. In determining CPUC-jurisdictional LSE forecasts, CEC applies a pro-rata adjustment to ensure that the aggregate forecasts in each TAC are within 1% of the reference forecast. For August 2020, pro-rata adjustments were only necessary in the PG&E area.

4. For the final year ahead-ahead forecasts, non-CPUC jurisdictional entities may submit updated forecasts to the CEC. Most revised forecasts are from LSEs whose load is related to water pumping and can vary significantly with hydrologic conditions. The decrease in non-CPUC jurisdictional load from the expected 4,333 MW in August to 4,022 MW reflects lower LSE forecasts of pumping load. CPUC-jurisdictional forecasts were 0.2% below the CPUC reference forecast. This left the total year-ahead forecast for August at 99.1% of the adjusted CAISO forecast total. In May and September, the year-ahead forecast total fell to 98.2%.

5. For the August month-ahead showing, LSE forecasts increased, with POU forecasts increasing to 4,169 MW. This brought the forecast total to 99.8% of CEC's adjusted CAISO forecast. In all summer months, aggregate month-ahead forecasts increased for both groups of LSEs compared to the year-ahead forecasts, and in total were within 1% of the CEC forecast.

Table A.2 lists all load serving entities (LSEs) in the CAISO footprint for summer 2020 by jurisdiction and type.

Table A.2: LSEs in the CAISO Footprint – Summer 2020

	Load Serving Entity	**Jurisdiction & Type**
1	Pacific Gas & Electric	CPUC - IOU
2	San Diego Gas & Electric	CPUC - IOU
3	Southern California Edison	CPUC - IOU
4	3 Phases Energy Services	CPUC - ESP
5	American Power Net Management	CPUC - ESP

	Load Serving Entity	Jurisdiction & Type
6	Calpine Power America-CA, L.L.C. (1362)	CPUC - ESP
7	Commerce Energy, Inc. (1092)	CPUC - ESP
8	Commercial Energy of California	CPUC - ESP
9	Constellation New Energy, Inc.	CPUC - ESP
10	Direct Energy, L.L.C.	CPUC - ESP
11	EDF Industrial Power Services (CA), LLC	CPUC - ESP
12	Noble Americas Energy Solutions LLC	CPUC - ESP
13	Pilot Power Group, Inc.	CPUC - ESP
14	Shell Energy North America	CPUC - ESP
15	Tiger Natural Gas	CPUC - ESP
16	UC Office of the President	CPUC - ESP
17	Apple Valley Clean Energy	CPUC - CCA
18	City of Solana Beach	CPUC - CCA
19	Clean Power Alliance of Southern California	CPUC - CCA
20	Clean Power San Francisco	CPUC - CCA
21	Desert Community Energy	CPUC - CCA
22	East Bay Community Energy	CPUC - CCA
23	King City Community Power	CPUC - CCA
24	Lancaster Choice Energy	CPUC - CCA
25	Marin Energy Authority	CPUC - CCA
26	Monterey Bay Community Power Authority	CPUC - CCA
27	Peninsula Clean Energy Authority	CPUC - CCA
28	Pico Rivera Innovative Metropolitan Energy	CPUC - CCA
29	Pioneer Community Energy	CPUC - CCA
30	Rancho Mirage Energy Authority	CPUC - CCA
31	Redwood Coast Energy Authority	CPUC - CCA
32	San Jacinto Power	CPUC - CCA
33	San Jose Clean Energy	CPUC - CCA
34	Silicon Valley Clean Energy	CPUC - CCA
35	Sonoma Clean Power	CPUC - CCA
36	Valley Clean Energy Authority	CPUC - CCA
37	Western Community Energy	CPUC - CCA
38	Arizona Electric Power Cooperative, Inc.	Non-CPUC
39	Bay Area Rapid Transit	Non-CPUC
40	Bear Valley Electric Services	Non-CPUC
41	CDWR	Non-CPUC
42	City and County of San Francisco	Non-CPUC

	Load Serving Entity	**Jurisdiction & Type**
43	City of Anaheim	Non-CPUC
44	City of Azusa	Non-CPUC
45	City of Banning	Non-CPUC
46	City of Cerritos	Non-CPUC
47	City of Colton	Non-CPUC
48	City of Corona Department of Water & Power	Non-CPUC
49	City of Industry	Non-CPUC
50	City of Vernon	Non-CPUC
51	City of Victorville	Non-CPUC
52	Eastside Power Authority	Non-CPUC
53	Kirkwood Meadows	Non-CPUC
54	Lathrop Irrigation District	Non-CPUC
55	Metropolitan Water District	Non-CPUC
56	Moreno Valley	Non-CPUC
57	NCPA	Non-CPUC
58	Pasadena Water & Power	Non-CPUC
59	Pechanga Tribal Utility	Non-CPUC
60	Port of Stockton	Non-CPUC
61	Power and Water Resources Pooling Authority	Non-CPUC
62	Rancho Cucamonga Municipal Utility	Non-CPUC
63	Riverside Public Utility	Non-CPUC
64	Silicon Valley Power	Non-CPUC
65	Valley Electric Association	Non-CPUC
66	WAPA - WDOE	Non-CPUC
67	WAPA - WFLS	Non-CPUC
68	WAPA - WNAS	Non-CPUC
69	WAPA - WPUL	Non-CPUC
70	WAPA - WSLW	Non-CPUC

Appendix B: Technical Discussion on Supply Conditions Based on Current Resource Planning Targets and Energy Market Practices

This appendix provides a more detailed, technical discussion of how the current resource planning targets have not kept pace to support the transition to a reliable, clean, and affordable resource mix and energy market practices in the day-ahead market that exacerbated the supply challenges under highly stressed conditions.

Supply-side resources are evaluated from the planning horizon into the operational time frame. Specifically, the resource adequacy (RA) capacity shown to the CAISO for August 2020 is compared to all resources that bid and were awarded in the day-ahead and real-time markets, and actual performance for August 14 and 15 peak and net-load peak periods. A separate analysis is provided for demand response resources. This analysis was conducted for both peak and net demand peak for August 14 and 15. Overall, actual generation from all resources was only 98% of the shown RA plus RMR allocation for August 2020 during the peak. During the net demand peak this decreased to 94%. When considering only shown RA resources (but assuming all wind and solar generation is RA capacity), this decreased to 90% during peak and 84% during the net demand peak. The resource-specific analysis did not attempt to quantify when RA resources may have provided above or below its shown amount so actual generation from the shown RA fleet may be higher or lower than provided in this Final Analysis.

Appendix B also includes a detailed discussion of the relevant energy market practices that impacted exports during August 14 and 15 and includes an expanded export analysis. Unlike the resource-specific analysis, the export analysis is a deeper dive and explicitly considers and differentiates between shown RA and non-RA resources. The analysis finds that during the Stage 3 Emergencies there were more non-RA resources than exports. Lastly, the appendix concludes with a brief analysis on Energy Imbalance Market transfers, showing that available real-time transfers were below the transfer cap during the Stage 3 Emergencies and that voluntary transfers helped the CAISO market on those challenging days.

The DMM is the CAISO's independent market monitoring body that reports on market design, behavior, and performance issues. The DMM is independently responsible for conducting research and presents any findings separately. The CAISO collaborates with its Department of Market Monitoring (DMM) on monitoring and investigating such issues.

On November 24, 2020, the CAISO's Department of Market Monitoring (DMM) released its independent review of system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020.[73] The DMM's analysis concurred with many of the key findings and recommendations of the Preliminary Analysis and confirmed that there was no single root cause but a series of factors that contributed to the emergencies. The DMM confirmed that "[c]ontrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation."[74]

B.2 Detailed Analysis on Supply Conditions Based on Current Resource Planning Targets

As described in Section 2, all load serving entities (LSEs) in the CAISO's BAA based their reliability planning on a 1-in-2 average weather forecast. The CPUC's RA program is based on a 1-in-2 average forecast plus a 15% planning reserve margin (PRM). The forecast used in the RA program is based the single forecast set developed by the CEC. The CEC sets the forecast for the CAISO footprint and works with LSEs to set the individual coincident forecasts for RA purposes. Based on the established methodology and timelines, the August 2020 obligation was based on the August 2018 IEPR Update transmission area monthly peak demand forecast of 44,955 MW, adjusted down to 44,741 MW and entered into the CAISO system by CEC staff as 44,740 MW. Table B.1 below shows the breakdown between CPUC jurisdictional LSEs and non-CPUC local regulatory authority (LRA) obligations and the resources and credits used to meet those obligations.

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[73] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[74] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 3.

Table B.1: August 2020 RA Obligation, Shown RA, RMR, and Credits

CPUC	Non-CPUC	**Total**	
40,570	4,169	**44,740**	CEC forecast for 1-in-2 August 2020 (adjusted)
6,086	588	**6,674**	Total 15% planning reserve margin
46,656	4,758	**51,413**	Total obligation
91%	9%	100%	
44,763	4,164	**48,926**	August 2020 system resource adequacy shown
261	29	**290**	Reliability Must Run (RMR) contracted resources
1,632	565	**2,197**	Credits provided by local regulatory authorities
46,656	4,758	**51,413**	Total resource adequacy, RMR, and credits

The CPUC jurisdictional LSEs comprise approximately 91% of the total load. Per the CPUC's RA program requirements, a 15% PRM is added to the peak of the 1-in-2 forecast for a total obligation of 46,656 MW. The non-CPUC local regulatory authorities vary slightly in their PRM requirements but collectively yield a 14% PRM for a total obligation of 4,758 MW. Approximately 500 MW or about 1% of the total load uses a PRM less than 15%. In total across both CPUC jurisdictional and non-jurisdictional entities, the PRM is 14.9% and the obligation for August 2020 was 51,413 MW.

There are three distinct categories used to meet the total obligation. The most straightforward is the RA capacity "shown" to the CAISO. This means the physical resource (either generation or demand response) is provided on a supply plan with the unique resource identification number (resource ID) to the CAISO system and noted as specifically meeting the August 2020 obligation. The second category of resources is Reliability Must Run (RMR) allocations from the CAISO. RMR resources are contracted by the CAISO pursuant to a reliability need and the capacity from these resources are allocated to the appropriate load serving entities to offset their obligations. The last category is "credits" to an LSE's obligation permitted by the LRA. A credit may cause a lower amount of total RA shown by the LSE scheduling coordinator to the CAISO. The composition of credited amounts is generally not visible to the CAISO and resources that are accounted for in the credits do not submit bids consistent with a must offer obligation and are not subject to availability penalties or incentives, or substitution requirements. The largest credited amount is from the CPUC at 1,482 MW which reflects the various demand response programs from the investor owned utilities (IOUs), including the emergency triggered Reliability Demand Response Resource (RDRR). Since credited resources are not shown directly on the RA supply plans, they are not considered RA supply and are reflected as non-RA capacity throughout this analysis.

After the publication of the Preliminary Analysis, the CAISO attempted to evaluate the performance of resources credited against the RA requirements but found that aside from the CPUC-credited demand response, all other credited capacity was either not in the CAISO market (*i.e.*, behind-the-meter backup generators) or reflected contracted capacity also not visible to the CAISO. Because the CAISO lacked the required information, the CAISO could not evaluate the performance of these resources. On the other hand, most of the CPUC's demand response is in the market and the CAISO used settlement quality information as well as data obtained information from the CPUC to evaluate CPUC-jurisdictional credited demand response resources. Below is a discussion of the CPUC-credited demand response resources based on the available data.

On August 27, 2020, the CAISO submitted proposed edits to its Business Practice Manual (BPM) for Reliability Requirements to stop the practice of accepting credits against RA requirements and begin requiring all RA resources to be explicitly shown on the RA supply plans.[75] Multiple stakeholders objected to the change and appealed the decision.[76] On December 9, 2020 the CAISO BPM Appeals Committee decided to hold any changes in abeyance until August 1, 2021, to allow for additional time to work constructively and collaboratively with stakeholders to resolve issues caused by the end of the crediting practice.[77] The CAISO will evaluate by August 21, 2021 whether or not the CAISO's expressed concerns about resource crediting have been addressed.

B.2.1 Planning Reserve Margin

As described in the background in Section 2, the 15% PRM in the RA program was finalized in 2004 to account for 6% contingency reserves needed by the grid operator with the remaining 9% intended to account for plant forced outages and higher than average demand. The PRM has not been revised since.[78]

Figure B.1 below compares August 14 and 15 actual peak, outages, and 6% contingency reserve requirement against the total PRM for August 2020. For August 14, contingency reserves were 6.3%, which reflects the fact that the actual load was higher than the forecast. In other words, based on the forecasted load of 44,740 MW, 6% contingency reserves are 2,669 MW. However on August 14, the actual peak was

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[75] *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

[76] See Appeals Committee information for PRR 1280: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AA347224-590D-47AC-ADA0-2E93A64CEF9C

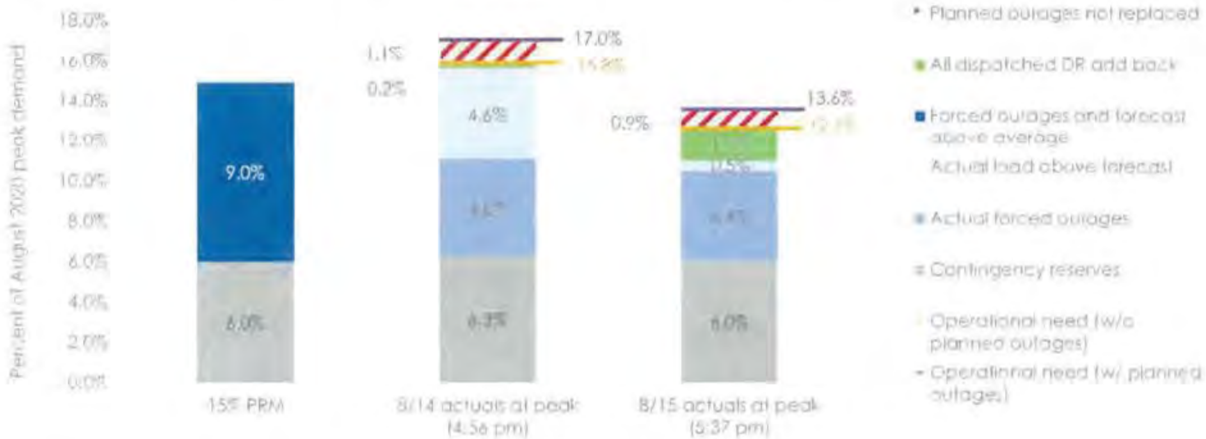
[77] *See:* http://www.caiso.com/Documents/ExecutiveAppealsCommitteeDecision-PRR1280-Dec092020.pdf

[78] One difference from 2004 is the original PRM allocated 7% to contingency reserves. The CAISO does carry another 1% in regulation up requirements. However, for the purposes of this analysis and to simplify the discussion, the 6% WECC requirement is used throughout.

46,802 MW and 6% is 2,808 MW. Compared to the original forecasted load, 2,808 MW is 6.3%.

On August 14 the actual load was 4.6% above forecast but does not include another 0.2% of load that was served by demand response. Adding back in the metered response of all demand response, load was 4.8% higher than forecasted. Total forced outages were 4.8%. Adding all these elements, the operational need for August 14 was 0.8% higher than the 15% PRM. In addition to forced outages, during the actual operating day the CAISO also had 514 MW and 421 MW of planned outages that were not replaced on August 14 and 15, respectively. The CPUC-approved PRM does not include planned outages under the assumption that planned outages will be replaced with substitute capacity or denied during summer months. Adding in the planned outages would increase the operational need to 2.0% higher than the PRM. On the other hand, the operational need for August 15 was below the 15% PRM at by 2.3% including only forced outages and 1.4% with planned outages.

Figure B.1: August 2020 PRM and Actual Operational Need During Peak (Updated)



Although a PRM comparison is informative, the rotating outages both occurred after the peak hour, as explained below.

B.2.2 Critical Grid Needs Extend Beyond the Peak Hour

The construct for RA was developed around peak demand, which until recently had been the most challenging and highest cost moment to meet demand. The principle was that if enough capacity was available at peak demand there would be enough capacity at all other hours of the day since most resources could run 24/7 if needed. With the increase of solar penetration in recent years, however, this is no longer the case. The single critical period of peak demand is giving way to multiple critical periods during the day. A second critical period is the net demand peak, which is the peak of load net of solar and wind generation and occurs later in the day than the peak. Although RA processes should be designed to meet load at all times throughout the day, the net demand peak is becoming the most challenging time period in which to meet demand at this time. As the grid transforms, other periods of grid needs may emerge in future.

Since 2016, the CAISO has worked with the CEC and the CPUC to examine the impacts of significant renewable penetration on the grid and found that solar generation in particular shifts the peak load to later in the day around 7 p.m.[79] This is because solar generation "may shift utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by [solar generation], with generation dropping off quickly as the evening hours approach."[80] On hot days, load later in the day may still be high, after the gross peak has passed, because of air conditioning demand and other load that was being served by behind-the-meter solar comes back on the system.

The CAISO evaluates this period by examining the net demand. The net demand is the demand that remains after subtracting the demand that is served by wind and solar generation. In Figure B.2 below, the difference between the demand curve (in blue) and the net demand curve (in orange) is largest in the middle of the day (approximately 10 a.m. until 4 p.m.) when renewables, especially solar, are generating at the highest levels and serving a significant amount of CAISO load. The system peak is before 6 p.m. However, as the sun sets, the difference between the demand and the net demand curves narrow, reflecting a reduction in wind and solar generation that the RA program does not recognize. Furthermore, as the sun sets, demand previously served by behind-the-meter solar generation is coming back to the CAISO system while load remains high. This means demand is decreasing at a slower rate than the net demand is increasing which creates higher risk of shortages around 7 pm, when the net demand reaches its peak (net demand peak). In Figure B.2 below, the net demand peak on August 14 of 42,237 MW is 4,565 MW lower than the peak demand but wind and solar generation have decreased by 5,438 MW during the same time period. On August 15, the system peak is again close to 5 p.m. and the net demand peak is slightly earlier at 6:26 p.m. The net demand peak is 41,138 MW, 3,819 MW lower than the peak demand, while wind and solar generation have decreased by 3,450 MW during the same time period. Note that the peak and net demand peak shown in Figure B.2 is already reduced by the impact of any demand response that dropped load.

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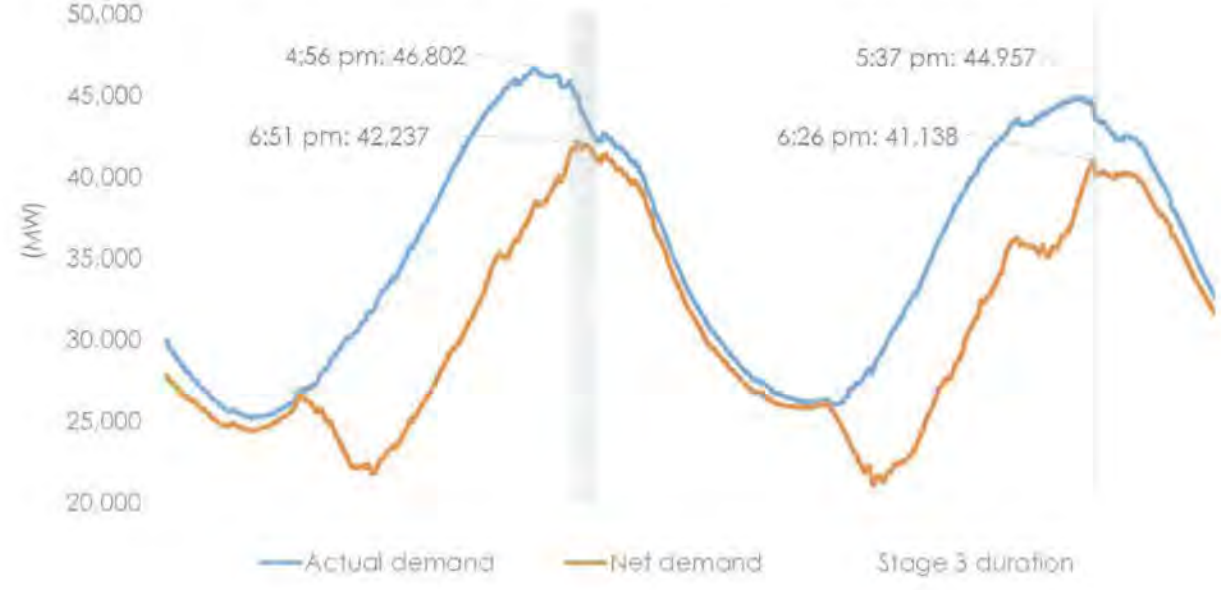
[79] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017. *See* Chapter 4: Peak-Shift Scenario Analysis.

[80] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017, p. 51.

Figure B.2: Demand and Net Demand for August 14 and 15



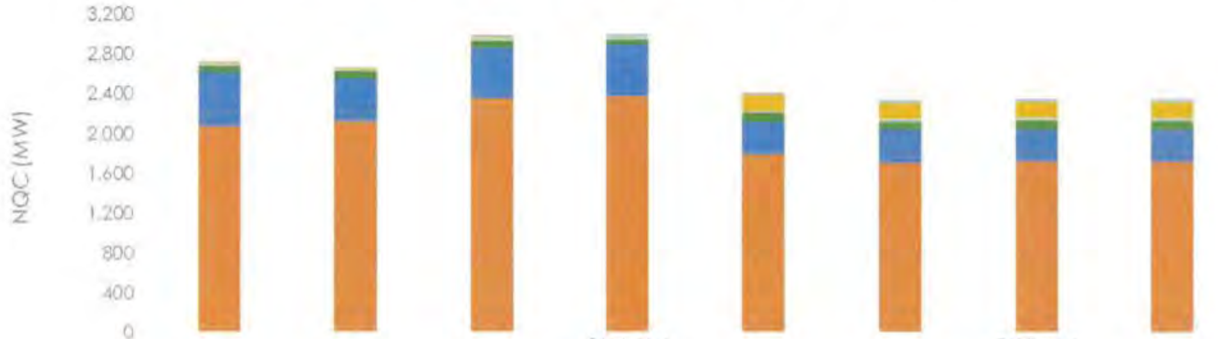
On August 14 the Stage 3 Emergency was declared at 6:38 p.m., right before the net demand peak at 6:51 p.m. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 p.m., just after the net demand peak at 6:26 p.m. Given the importance of both the peak demand and net demand peak hours, this analysis will examine both as compared to the planning time frame.

B.2.3 Overview of Supply and RA Resources Shown to the CAISO

This section provides an overview of supply, with a focus on the RA capacity shown to the CAISO as well as other related capacity and credits to meet RA requirements and their performance. The timeline traces the resources from the planning horizon into the operational (day-ahead and real-time markets) bidding, dispatch, and actual performance for August 14 and 15 peak and net demand peak periods.

Outage analysis is particularly complicated as the term "outage" can reflect several conditions why generators are not able to perform. For example, some outages may be temporal such as a noise limitation permit that restricts plant operations between certain hours of the day while other outages may be due to mechanical failure. In these two examples, if the outage capacity is added across the day, the noise limitation permit may artificially inflate the actual outage at the time of interest. If the noise permit only applies from midnight to 6:00 a.m., this outage would not be relevant to an analysis of the 7:00 p.m. net demand peak. Therefore, the RA plant outage information used in this analysis has been carefully analyzed for four snapshots relevant to the discussion. For each day on August 14 and 15, the outages are reported for the time of peak, net demand peak, and when the Stage 2 and 3 Emergencies were declared. Figure B.3 below provides the four snapshots based on the net qualifying capacity (NQC) capacity.

Figure B.3: RA Outage Snapshot for August 14 and 15



	8/14, Stage 2 (3:25 pm)	8/14, Peak (4:56 pm)	8/14, Stage 3 (6:38 pm)	8/14, Net demand peak (6:51 pm)	8/15, Peak (5:37 pm)	8/15, Stage 2 (6:16 pm)	8/15, Net demand peak (6:26 pm)	8/15, Stage 3 (6:28 pm)
■ Other	10	5	7	7	27	26	26	26
■ Wind	0	0	13	13	6	6	6	6
■ Solar	6	7	7	7	155	155	155	155
■ Import	29	19	29	29	20	29	29	29
■ Geothermal	69	69	60	60	79	79	79	79
■ Hydro	535	424	508	509	336	335	335	335
■ Natural gas	2,070	2,123	2,352	2,371	1,788	1,704	1,714	1,714
Grand total	2,719	2,647	2,976	2,996	2,411	2,333	2,344	2,344

The overall outage level may have been reduced by the CAISO's RMO issued for both days. Most of the outages were comprised of the natural gas-fired fleet, which is largely driven by outage cards submitted because of high ambient temperatures, which impact a thermal resource's ability to produce generation.[81]

Beyond outages, a variety of factors impacted RA resources' ability to fully bid their capacity and ultimately provide energy. Figure B.4 through Figure B.7 below provide categories of unused RA capacity for each day and time frame. As described above, plant forced outages and derates (*i.e.*, a reduction in the resource's capacity) largely affected the natural gas fleet.

The next largest category is congestion due to transmission constraints. This limits imports which is a category that includes both non-resource-specific resources as well

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[81] Note that the Blythe Energy Center outage is reflected in the outage number and the outage was entered by the time a Stage 2 Emergency was declared. On the other hand, the Panoche Energy Center ramp down is not included in the above outage numbers because this was not an actual plant outage and instead was a resource deviation, which the CAISO understands to be due to an erroneous instruction from the scheduling coordinator to the plant.

as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station. Congestion is largely attributed to transmission constraints on imports from the Pacific Northwest. Through the month of August, a major transmission line in the Pacific Northwest upstream from the CAISO system was forced on outage due to a storm in May 2020 and thus derated the California Oregon Intertie (COI). The derate on COI congested the usual import transmission paths across both COI and Nevada-Oregon Border (NOB).[82]

Hydro generation was affected by a variety of reasons such as derates but also a lack of day-ahead bids on RA capacity that did not have any or only had a must-offer obligation on a portion of its capacity.

Lastly, wind and solar unused RA capacity largely reflects the difference between the shown RA value and the actual production capability of these resources.

Figure B.4: August 14 Peak (4:56 p.m.) Unused RA Capacity by Resource Type

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[82] *See* Grizzly-Portland General Electric (PGE) Round Butte No 1 500 kV Line at: https://transmission.bpa.gov/Business/Operations/Outages/OutagesCY2020.htm

Figure B.5: August 14 Net Demand Peak (6:51 p.m.) Unused RA Capacity by Resource Type

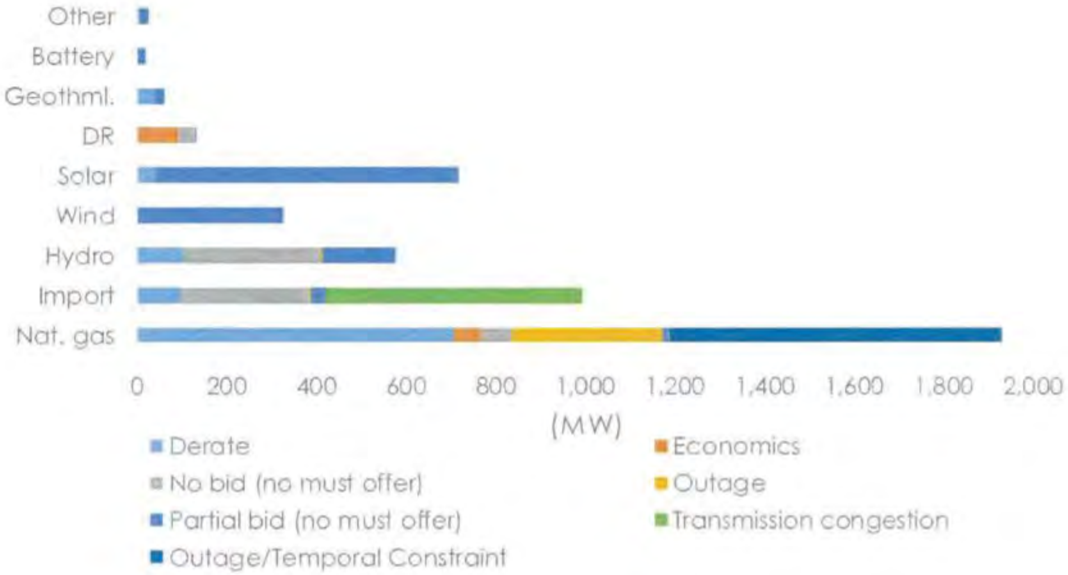


Figure B.6: August 15 Peak (5:37 p.m.) Unused RA Capacity by Resource Type

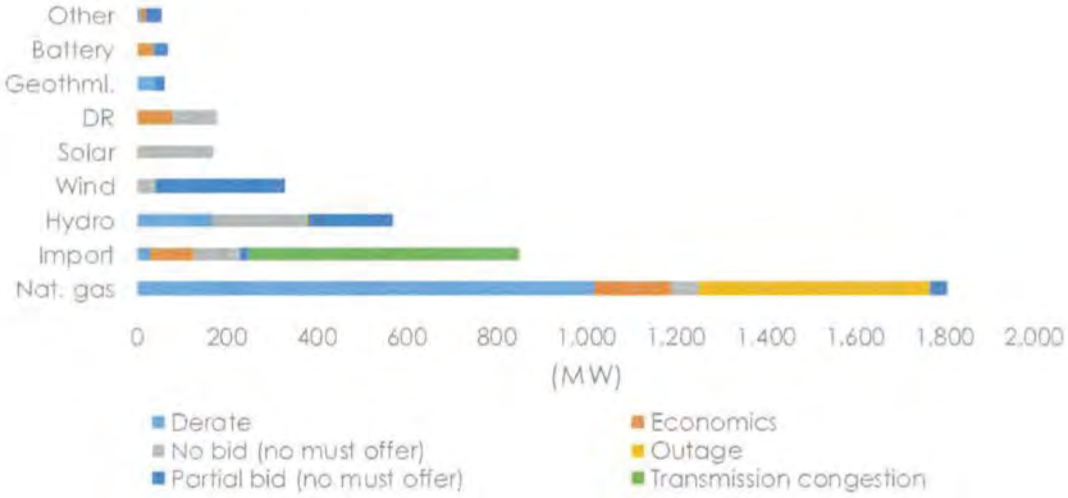
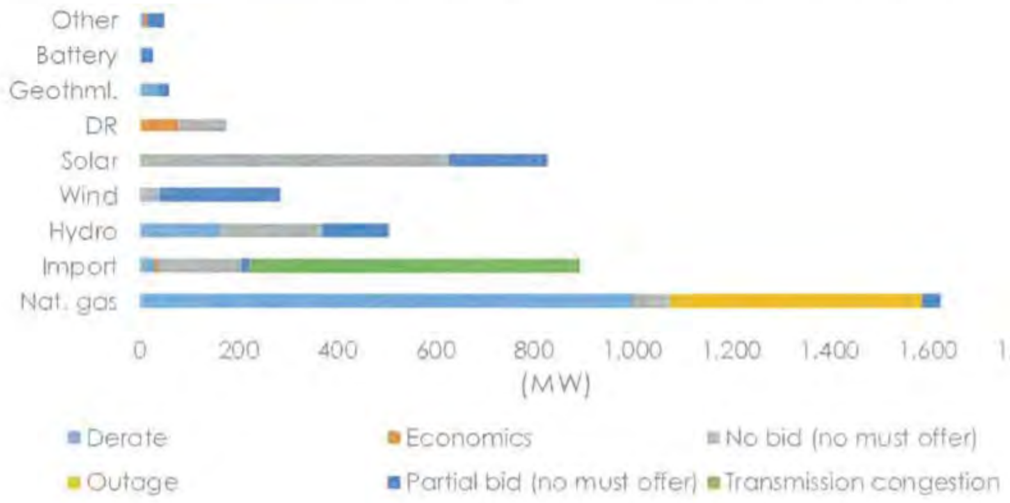


Figure B.7: August 15 Net Demand Peak (6:26 p.m.) Unused RA Capacity by Resource Type



B.2.3.1 Supply-Side RA Shown Capacity, Bids, Awards, and Energy Production

The CAISO clears most of its real-time need in the day-ahead market in hourly blocks, which includes both energy and ancillary services (A/S). Ancillary services are reliability services that the CAISO co-optimizes and clears with energy needs and includes both contingency reserves and regulation up and down capability. The following analysis compares the supply-side fleet from the planning horizon (August 2020 shown RA and RMR allocations), through day-ahead (bids and awards), and into real-time (real-time awards and actual energy production). Based on CAISO rules, only resources shown to the CAISO as RA are considered RA capacity. RA resources that generate above their shown amounts or resources with RA long-term contracts that are not shown to the CAISO are not consider RA resources under CAISO rules. Two simplifying assumptions were made for the analyses. First, all wind and solar is assumed to count towards RA though that has not been validated. Second, rather than classify all remaining bids and generation as non-RA, the analyses below classify such bids and generation more broadly as "above RA."[83] If shown RA resources bid or generate below the amount

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[83] Except for the more detailed export analysis in Appendix B, this Final Analysis does not distinguish resources within the "above RA" category, the CAISO's Department of Market Monitoring (DMM) produced an assessment that provides greater granularity. The DMM's analysis does not change the conclusions of this Final Analysis. See Section 3.6 Resource adequacy capacity in Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at:

shown to the CAISO, those bids or generation may be replaced by non-RA resources. Note that any credited resources that bid or are awarded are considered above the RA shown amounts. (Demand response is addressed separately in the next subsection.)

While not reflected in the following analysis, the DMM's independent review of system conditions from mid-August to early September differentiated the "above RA" bids into three categories: (1) RA resources bidding above the RA shown amounts; (2) resources within the CAISO not shown as RA and (3) non-RA import resources.[84] The DMM indicates that there was approximately 3,000 MW and 2,500 MW available to the real-time market from RA resources bidding above their RA shown amounts during the net demand peak on August 14 and 15, respectively.[85] Nonetheless, the DMM analysis shows that bids from all RA resources made available to the real-time market on August 14 and 15, even above what was shown to the CAISO as RA capacity, were not sufficient to meet demand and WECC-required 6% operating reserve requirements during the net demand peak.[86] Note that this part of DMM's assessment does not account for RA resources that bid into the market but were not cleared, such as RA imports that were economically displaced by lower-priced imports due to transmission congestion, as discussed in more detail below. In addition, the DMM notes that day-ahead bids from RA resources, including bid quantities from RA resources above their RA showings, were not sufficient to meet the load forecast plus ancillary service requirements on August 17 and 18. In all cases, the DMM report also reflects that capacity was limited and DMM recommends that RA requirements are increased to more accurately reflect increasing risk of extreme weather events (*e.g.*, beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system RA targets).[87]

Figure B.8 through Figure B.11 below overlay the total shown RA supply plus RMR allocations (blue markers) on the amount of both RA and above RA day-ahead bids for

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http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[84] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 30.

[85] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, Figure 3.21, p. 32.

[86] Specifically, the requirements referred to here are market requirements, losses, spinning and non-spinning reserves.

[87] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 4.

peak and net demand peak on August 14 and 15, respectively.[88] Generally the shown RA resources bid 90% or more of their capacity for energy and ancillary services in the day-ahead market. In particular, natural gas and RA import bids were 95% or higher as compared to the shown RA. The main outliers are solar and wind generation as these resources produce as capable, which varies from the shown RA amounts. Especially during peak, solar day-ahead bids were up to three times as much as the shown capacity. Of note, there was also 2,500 to 3,500 MW of import bids above the shown RA amount.

Figure B.8: August 14 Peak (4:56 p.m.) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

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[88] For ease of discussion, residual unit commitment is included in RA and above RA energy awards.

Figure B.9: August 14 Net Load Peak (6:51 p.m.) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

Figure B.10: August 15 Peak (5:37 p.m.) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

Figure B.11: August 15 Net Demand Peak (6:26 p.m.) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

Figure B.12 through Figure B.15 below overlay the total shown RA supply plus RMR allocations (blue markers) as compared to the amount of both RA and above RA day-ahead awards for peak and net demand peak on August 14 and 15, respectively. As noted above, several factors impacted the resource fleet in different ways. Natural gas generators experienced a higher level of planned and forced outages and as such, RA natural gas resources were awarded on average only 93% of the shown capacity. The average for RA imports decreased to slightly below 90%. As discussed above, transmission congestion limited the physical import capability for RA imports. Because of this congestion, lower-priced non-RA imports cleared the market instead of higher-priced RA imports. Consequently, the amount of energy production from RA imports can be lower than the level of RA imports shown to the CAISO on RA supply plans. All other resources stayed relatively the same as compared to the day-ahead bid.

Figure B.12: August 14 Peak (4:56 p.m.) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

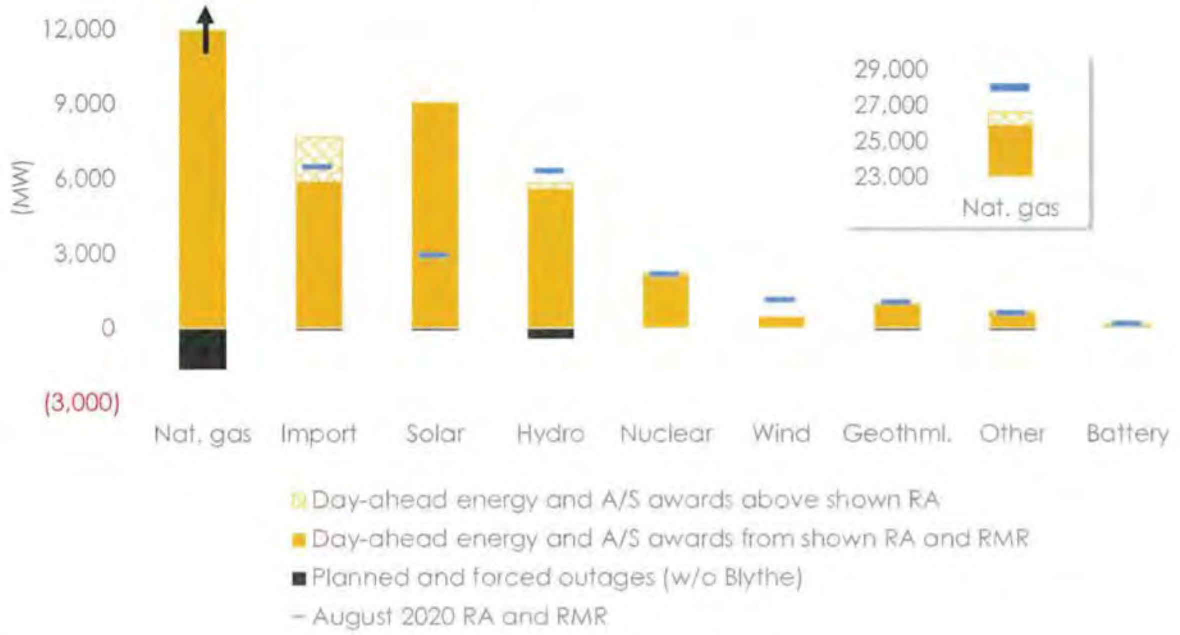

Figure B.13: August 14 Net Demand Peak (6:51 p.m.) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

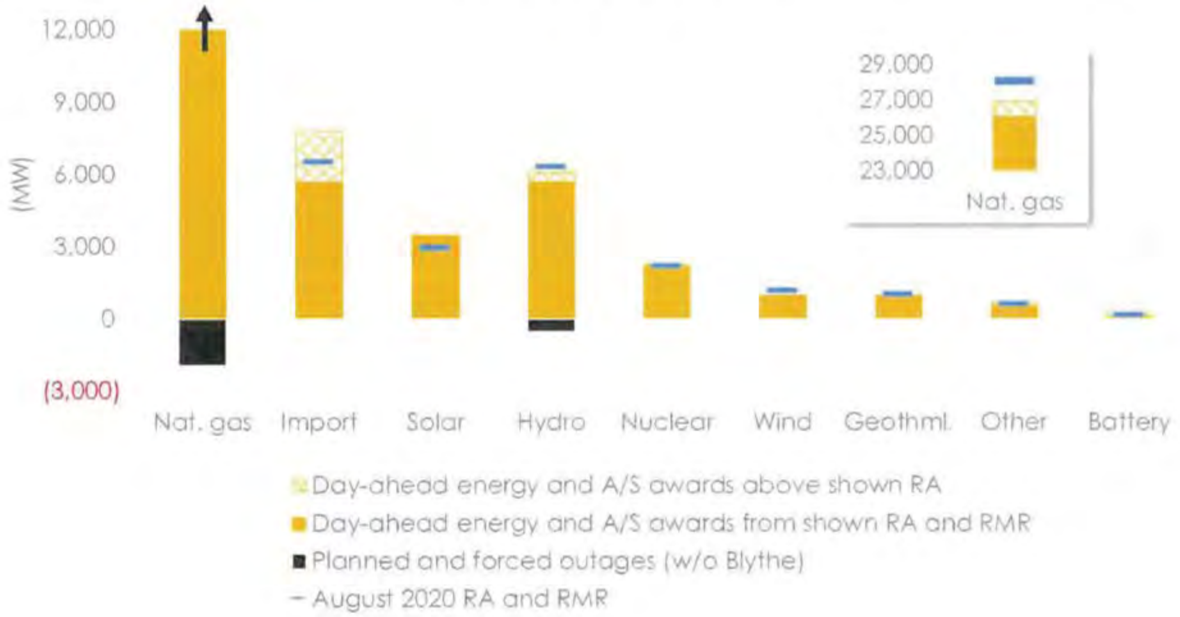

Figure B.14: August 15 Peak (5:37 p.m.) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

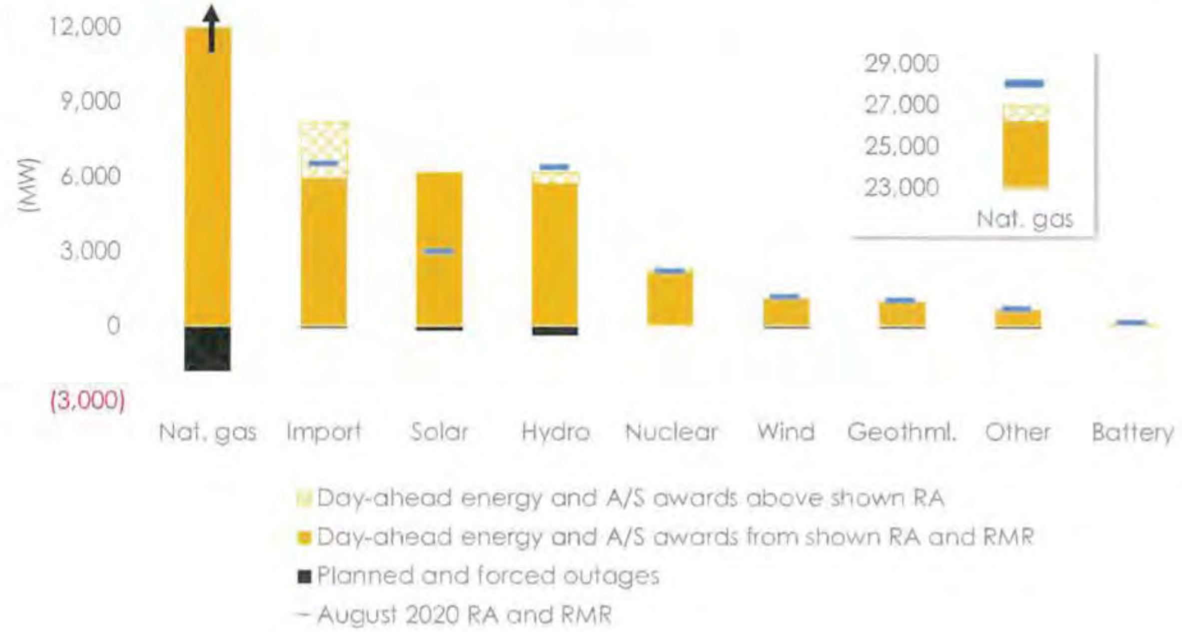

Figure B.15: August 15 Net Demand Peak (6:26 p.m.) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

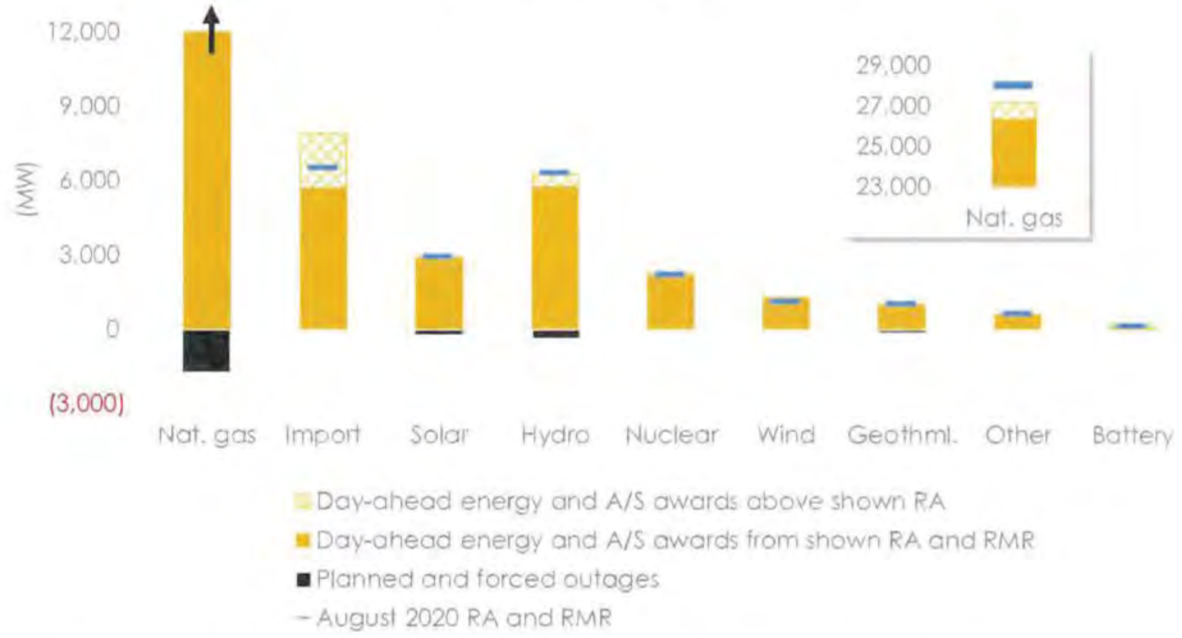

Figure B.16 through Figure B.19 below overlay three different time periods for the peak and net demand peak on August 14 and 15. The blue markers show the levels of capacity expected to provide energy either as RA or RMR for August 2020. The solid yellow bars show where resources obligated to provide energy under resource adequacy requirements were expected to produce based on instructions issued in the CAISO's real-time market. The yellow cross-hatched bars show the same targets for resources that bid into the market but were not obligated to offer their energy. The black bars show planned and forced outages. The actual energy delivered based is shown by green circles. Overall real-time awards were very similar to the day-ahead awards across all resources. However, energy production did vary for specific resources and that may be due to events happening in the moment or provision of ancillary services.

The RA natural gas fleet collectively generated approximately 85% of its shown RA value. The difference between real-time awards and actual generation is likely attributed to forced outages and derates due to the extreme heat. Even though the CAISO had issued an RMO notification for August 14 through 17, plants that were already on outage may not have been able to return to service safely within the time frame and derates due to extreme temperatures are not uncommon.[89]

Actual energy generation from the hydro generation fleet may seem low, on average 73% of the shown RA value across both days and time periods, but this does not include the provision of necessary ancillary services. Real-time ancillary services awards for shown RA hydro range from 600 MW to a high of 1,500 MW during the August 14 peak demand. Although actual generation production and ancillary service awards are not additive, analyzing both provides a fuller picture of the hydro fleet performance.

Solar production also varied from the real-time awards. Although generation during the peak remained above the shown RA values, it was half that during the net demand peak hours on both days. Solar generators collectively produced 1,600 to 4,200 MW more than the August RA values at peak but 1,000 to 1,200 MW less at the net demand peak.

Wind generators on the other hand did not have a consistent pattern with generation at only 30% (or 800 MW less) during the August 14 peak but almost 140% (or 400 MW more) during the August 15 peak. During the net demand peak, production was 40% (600 MW less) and 80% (200 MW less) of the total shown RA values for August 14 and 15, respectively.

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[89] The forced outage of the Blythe Energy Center and the erroneous dispatch at the Panoche Energy Center contributed to this difference.

Figure B.16: August 14 Peak (4:56 p.m.) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR (Updated)

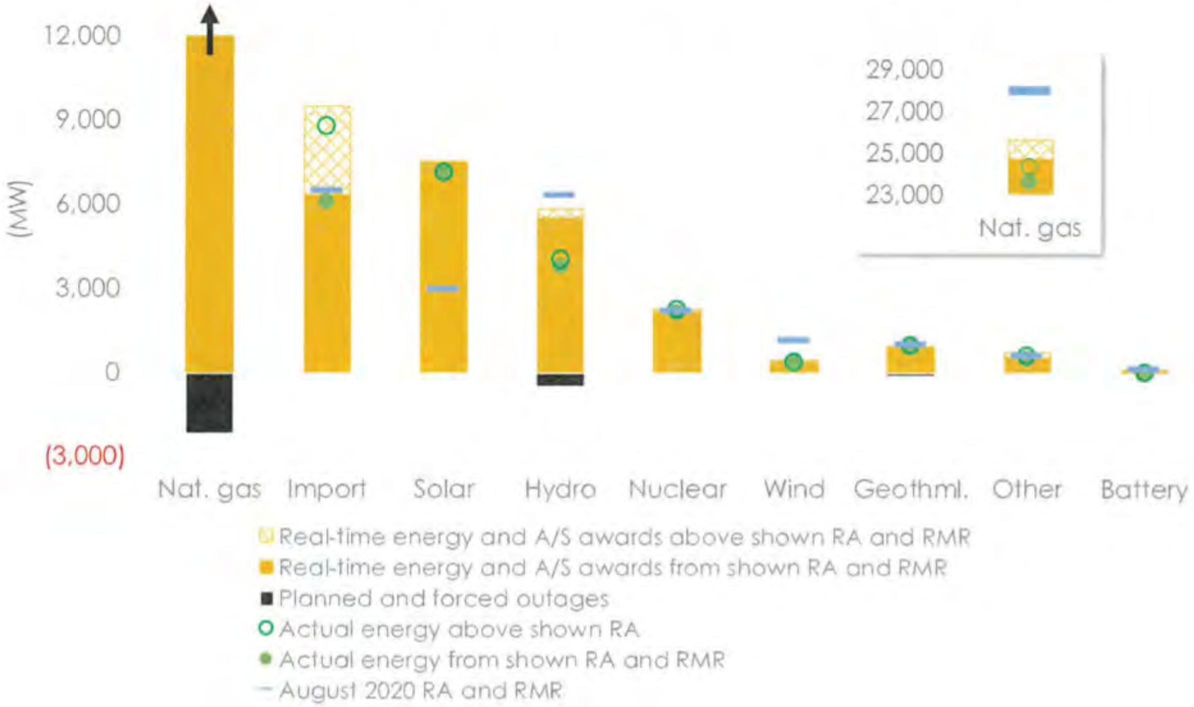

Figure B.17: August 14 Net Demand Peak (6:51 p.m.) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR (Updated)

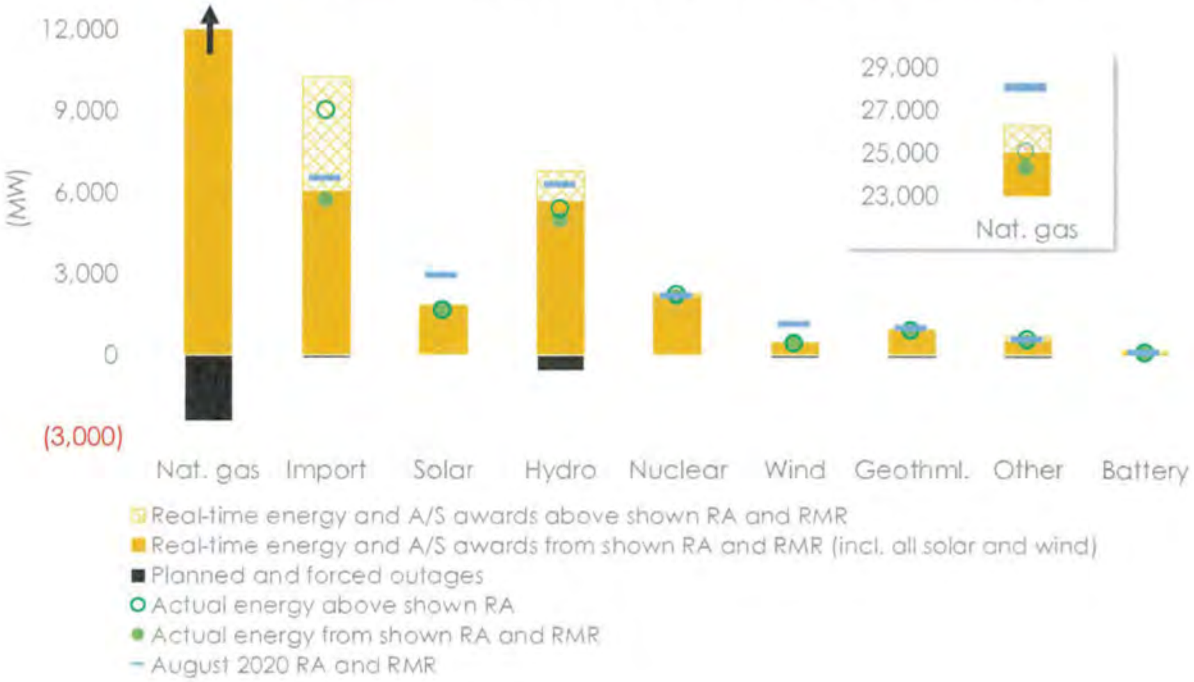

Figure B.18: August 15 Peak (5:37 p.m.) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR (Updated)

Figure B.19: August 15 Net Demand Peak (6:26 p.m.) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR (Updated)

B.2.3.2 Demand Response Analysis for Credits and Shown RA

Current market-integrated demand response programs are designed to reduce demand when the programs are dispatched based on market needs. They take on many forms but in the CAISO market there are two main programs that bid into the CAISO's wholesale markets and are dispatched similar to a power plant: emergency and economic demand response.

Emergency demand response programs (reliability demand response resources or RDRR) in the CAISO market are largely triggered by the CAISO after at least a Warning is declared though a small amount can be bid into the day-ahead market economically. These programs are managed by the IOUs and are credited by the CPUC against the RA requirement of CPUC jurisdictional LSEs. The IOU and non-IOU third party providers also provide non-emergency economic demand response (proxy demand response or PDR). IOU PDR is credited like RDRR, while the non-IOU PDR is mostly shown as RA to the CAISO (with only a small portion credited against the RA requirement).

CPUC jurisdictional LSEs' total August 2020 credits were 1,632 MW, representing 3.5% of their total obligations.[90] Of this total credit, 1,472 MW reflects IOU emergency and economic demand response programs, the vast majority of which is the RDDR emergency demand response programs that are triggered by CAISO's emergency protocols and remainder consists the IOUs' economically bid PDR demand response programs. Another 10 MW of credited demand response is attributed to non-IOU PDR. All credited amounts include "gross up" credits the CPUC applies to demand response resources to reflect their "preferred" resource status in California's loading order. These credits translate to approximately 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies.

Although these resources are not visible on supply plans to the CAISO, the CPUC publishes the capacity values and the IOUs provide daily availability reports to the CAISO.[91] Table B.2 below summarizes the demand response RA and credits against the RA requirements for August and September 2020.

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[90] Non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of their total obligations.

[91] *See:* "2020 IOU Demand Response Program Totals" at https://www.cpuc.ca.gov/General.aspx?id=6311

Table B.2: August and September 2020 Demand Response Credited and Shown RA

August 2020	**Credited**	**Shown RA**
Reliability Demand Response Resource (RDRR)	1,115 MW – IOU	n/a
Proxy Demand Response (PDR)	358 MW – IOU 10 MW – Non-IOU	243 MW – Non-IOU
Total	**1,482 MW**	**243 MW**
September 2020		
Reliability Demand Response Resource (RDRR)	1,087 MW – IOU	n/a
Proxy Demand Response (PDR)	312 MW – IOU 10 MW – Non-IOU	237 MW – Non-IOU
Total	**1,409 MW**	**237 MW**

Note: All credited amounts include transmission and distribution loss factors and planning reserve margin gross up.

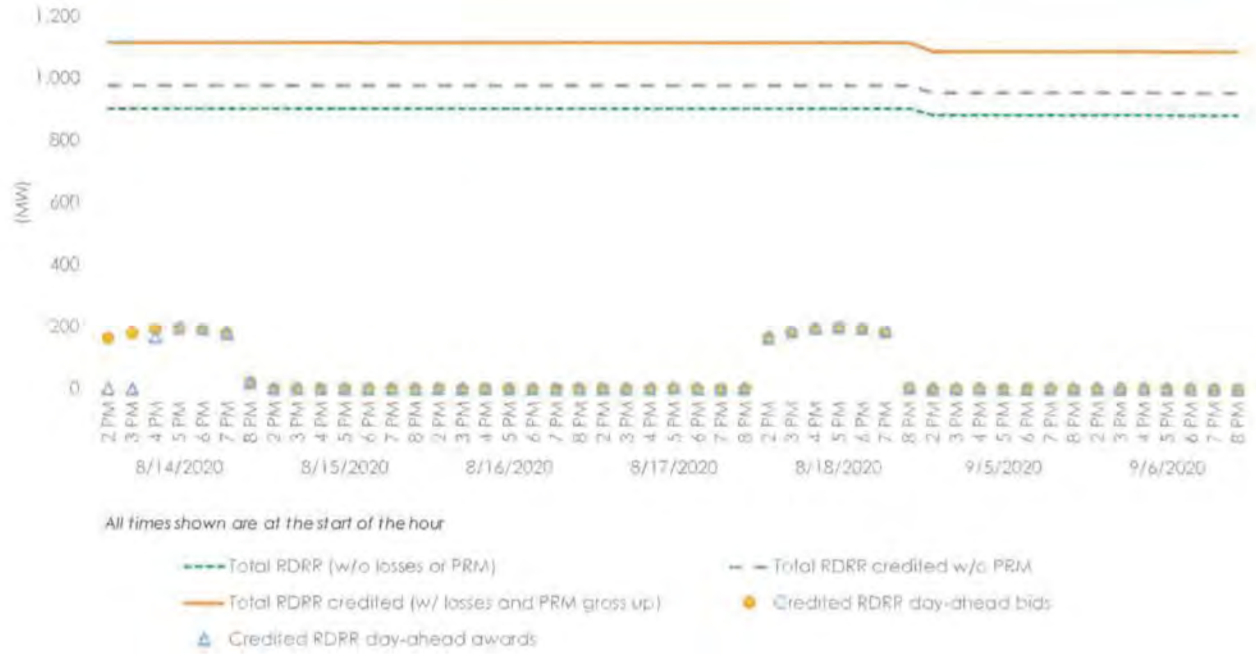
The following series of figures compares three combinations of credited and shown demand response:

- Figure B.20 and Figure B.21 – day-ahead and real-time bids credited RDRR;
- Figure B.22 and Figure B.23 – day-ahead and real-time credited PDR; and
- Figure B.24 and Figure B.25 – day-ahead and real-time PDR shown as RA to the CAISO.

Note that consistent with their must offer obligations, most PDR resources are not available on weekends by design (and for clarity, all times shown in the figures are the beginning of the hour, rather than the typical CAISO "Hour Ending" convention).

During August and September 2020, all RDRR resources were registered to the three large IOUs. As noted above, though most of RDRR is triggered in real-time by a CAISO declaration of at least a Warning, a small amount may be economically bid into the CAISO day-ahead market. Figure B.20 compares the day-ahead bids (yellow dots) and awards (blue triangles) of credited IOU RDRR from August 14 through 18 and also for September 5 and 6. These are the days during the mid-August extreme heat wave as well as the Labor Day heat wave where the CAISO called at least a Warning. Credited RDRR in the CAISO market is comprised of three factors. The first is the expected load curtailment from 4 p.m. to 9 p.m. based on the CPUC's QC methodology (green dotted line). The CPUC then adds to this amount a transmission and distribution losses gross up factor (grey dashed line).[92] Lastly, the entire amount is scaled up by the 15% PRM (solid orange line). The CPUC approved these gross up factors to reflect the equivalent procurement of supply-side RA resources that would be required to meet demand in the absence of demand response resources being credited, consistent with demand response's "preferred resource" status in California's loading order. These credits translate to approximately 10% for avoiding transmission and distribution losses, and 15% for planning reserve margin procurement that is avoided for customers who agree to drop load in grid emergencies.

Figure B.20: Credited IOU Reliability Demand Response Resource Day-Ahead Bids and Awards



All times shown are at the start of the hour

Figure B.21 below provides real-time information for credited RDRR. Rather than bids and awards, the RDRR in real-time is triggered by the CAISO declaring at least a Warning, which it did for all the dates shown below. The figure reproduces the same three factors of crediting discussed above and compares them to the amount of RDRR available as reported by the IOUs on the daily availability reports sent to the CAISO (red dots). The figure also includes the RDRR available for dispatch at the time requested by the CAISO[93] (blue squares). Both amounts can differ from the credited amounts (for

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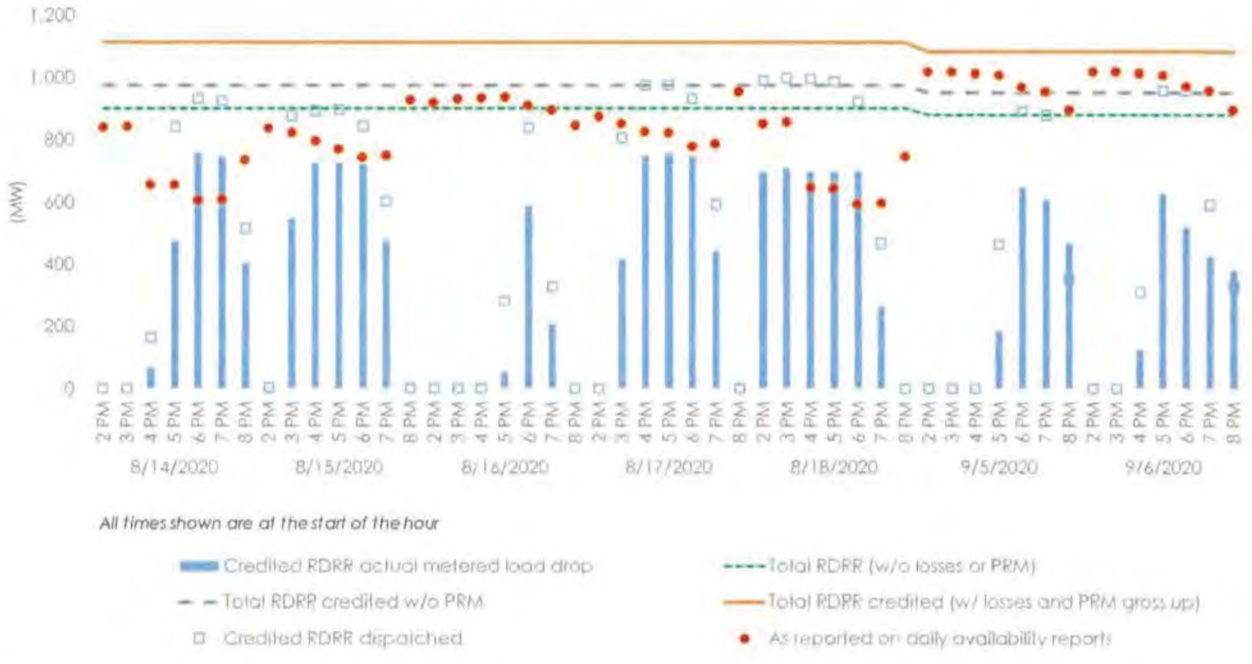
[92] See CPUC Decision15-06-063. The transmission and distribution losses gross up factors are: Pacific Gas & Electric 1.097; San Diego Gas & Electric 1.096; and Southern California Edison 1.076.

[93] In CAISO settlements terminology this is the Total Expected Energy.

instance, if a facility is offline due to maintenance it will have no load to drop). Lastly, the figure shows the RDRR actual metered load drop (blue bars), which is the total load drop in response to day-ahead and real-time awards. All times shown are the beginning of the hour.

Figure B.21: Credited IOU Reliability Demand Response Resource Real-Time Availability, Dispatch, and Performance



All times shown are at the start of the hour

RDRR is comprised of emergency demand response with certain programmatic limitations such as one call per day, 10 calls per month, and a maximum of a six hour duration per call. Therefore, if the RDRR is called too early in the day, it may exhaust its response before the greatest need on the grid. Furthermore, these programs may respond as fast as within 20 minutes or need as long as 40 minutes to fully curtail load. None of the above limitations are CAISO market limitations or rules.

Settlement quality metered data is currently available two months after the trade date and is used to measure the delivery of demand response services relative to a baseline. The baseline line methodologies have been in effect since 2010.[94] Although the CAISO has several sub-categories of demand response and thus baseline methodologies, the four most prevalent are discussed below and apply to both RDRR and PDR, whether credited or shown as RA.

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[94] FERC Order in ER10-765, July 15, 2010.

- **Ten in Ten Methodology** - Performance of the PDR or RDRR using this methodology is generally determined through a pre-determined baseline calculation using the last 10 non-event days with a look back window of 45 days and a bidirectional adjustment capped at 20%. PDR or RDRR using behind-the-meter generation to offset demand may submit for use, in the Ten in Ten Methodology, meter data reflecting the total gross consumption, independent of any offsetting energy produced by separately metered behind-the-meter generation.

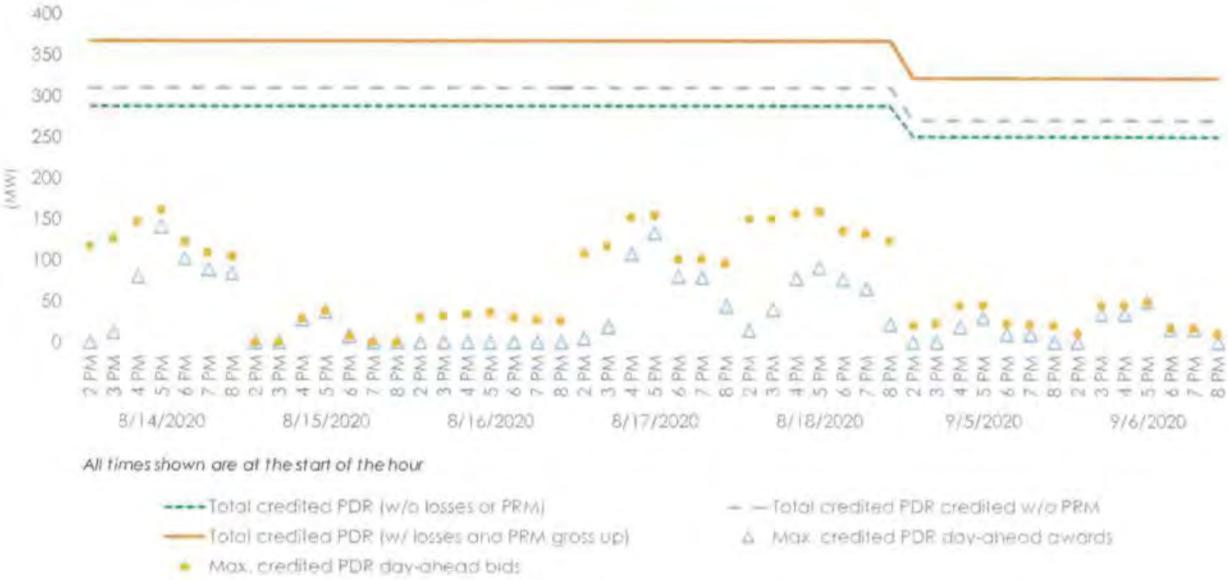
- **Five in Ten Methodology** - Performance of the PDR or RDRR using this methodology is generally determined through a pre-determined baseline calculation using the last five non-event days with a look back window of 45 days and a bidirectional adjustment capped at 1.4 (71% to 140%). PDR or RDRR using behind-the-meter generation to offset demand may submit for use, in the Five in Ten Methodology, meter data reflecting the total gross consumption, independent of any offsetting energy produced by separately metered behind-the-meter generation.
    - PDR or RDRR composed of both residential and nonresidential customers may choose to calculate separate baselines for the different customer classes using a combined methodology. Total performance is the sum of the Ten in Ten and Five in Ten performances.

- **Control Group Methodology** - Performance of the PDR or RDRR using this methodology will identify a control group that must consist of 150 distinct end users (or more), that are registered in the CAISO's demand response system and that do not respond to CAISO dispatch. The control group must have nearly identical demand patterns and be geographically similar such that they experience the same weather patterns and grid conditions as the PDR and RDRRs that respond to the dispatch (Treatment Group). The control group's aggregate demand during the same trade date and trade hour as the demand response event, divided by the relevant number of end users in the "Treatment" group will define the baseline.

- **Weather Matching Methodology** - Performance of the PDR or RDRR using this methodology is generally determined by development of a baseline using the four days, from a pool of non-event days, with the closest daily maximum temperature to the day in which the event occurred. Meter data is collected for 90 calendar days prior to the event day, working sequentially backwards from the trading day under examination and matching business and non-business days and excludes outages. The weather matching methodology has a bidirectional adjustment capped at 1.4 (71% to 140%).

Figure B.22 below compares the day-ahead bids and awards of credited IOU and non-IOU PDR for the same days and hours as the RDRR analysis for ease of comparison. Like credited RDRR, the CPUC credits all IOU PDR and some non-IOU PDR with the same transmission and distribution and 15% PRM gross up factors. Unlike RDRR, PDR does not require a CAISO trigger and is bid and dispatched in the CAISO market like a generation resource.

Figure B.22: Credited IOU and Non-IOU Proxy Demand Response Day-Ahead Bids and Awards



All times shown are at the start of the hour

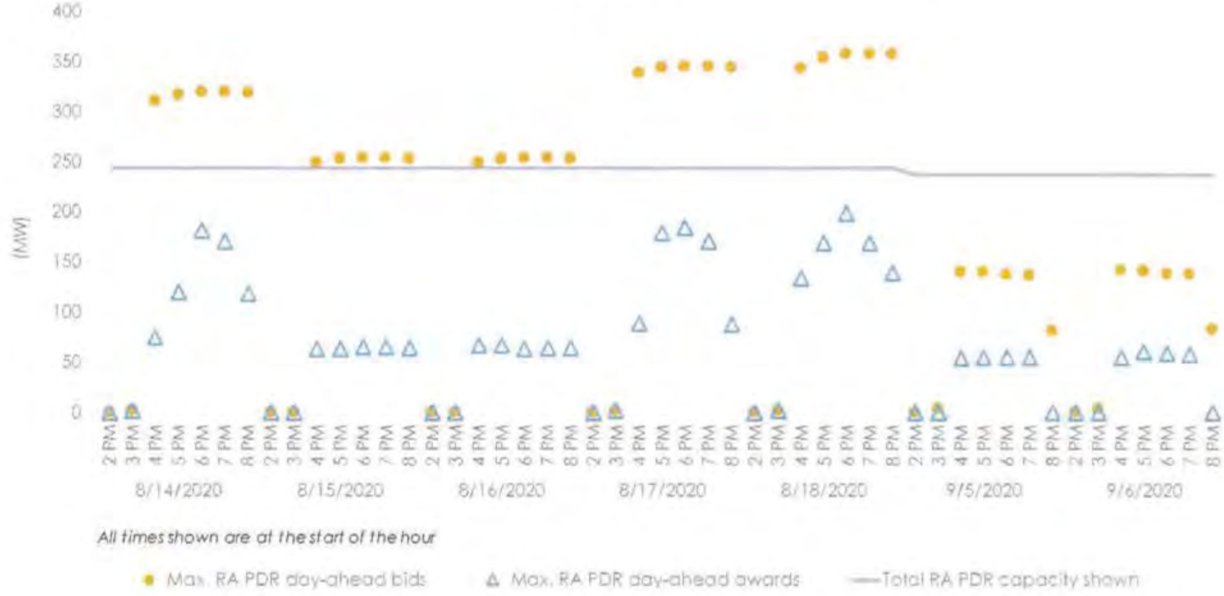
Figure B.23 below is the real-time data for credited IOU and non-IOU PDR for the same days and hours as the RDRR analysis for ease of comparison. The maximum real-time bids (yellow dots) are compared against the maximum real-time energy awards (blue triangles). Actual response (blue bars) is determined by the meter data and the baseline methodologies discussed above. The actual response reflects total load drop from both day-ahead and real-time awards. All times shown are the beginning of the hour.

Figure B.23: Credited IOU and Non-IOU Proxy Demand Response Real-Time Bids, Awards, and Performance

All times shown are at the start of the hour

Unlike the IOU demand response, non-IOU PDR is mostly shown as RA capacity which does not have a transmission and distribution loss factor nor a 15% PRM gross up. Figure B.24 below compares the total shown RA capacity (purple line) to the maximum day-ahead market bids (yellow dots) and awards (blue triangles). All times shown are the beginning of the hour.

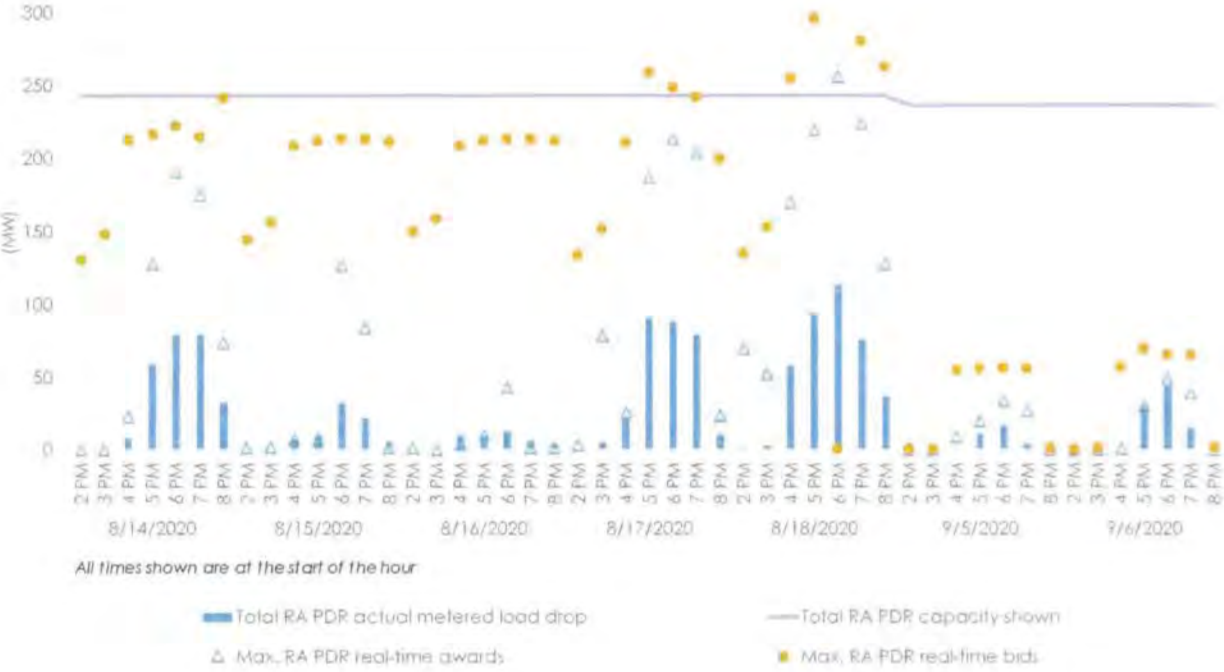
Figure B.24: Non-IOU Proxy Demand Response Shown as RA Day-Ahead Bids and Awards



All times shown are at the start of the hour

Figure B.25 compares the total shown RA capacity (purple line) to the maximum real-time market bids (yellow dots), awards (blue triangles), and actual metered load drop (blue bars). Actual response is determined by the meter data and the baseline methodologies discussed above. The actual response reflects total load drop from both day-ahead and real-time awards. The same days and hours as the RDRR analysis are shown for ease of comparison. All times shown are the beginning of the hour.

Figure B.25: Non-IOU Proxy Demand Response Shown as RA Real-Time Bids, Awards, and Performance



All times shown are at the start of the hour

Table B.3 below summarizes the demand response performance during the August 14 and 15 Stage 3 events. The comparison is benchmarked against the metered load drop of each of the three categories of demand response as a percentage of the RDRR available or PDR awards and each of the three factors as applicable.

Table B.3: Comparison of Demand Response Performance During August Stage 3 Events

During 8/14 Stage 3	Metered load drop	RDRR dispatched or PDR real-time awards	% metered load drop	Credited (w/o losses or PRM gross up) or shown RA	% metered load drop	Credited w/o PRM	% metered load drop	Credited (w/ losses and PRM gross up)	% metered load drop
IOU RDRR (credited)	762	935	81%	904	84%	978	78%	1,115	68%
PDR (credited)	69	101	68%	288	24%	311	22%	368	19%
PDR (RA)	79	191	41%	243	33%	n/a	n/a	n/a	n/a
During 8/15 Stage 3									
IOU RDRR (credited)	722	846	85%	904	80%	978	74%	1,115	65%
PDR (credited)	2	8	30%	288	1%	311	1%	368	1%
PDR (RA)	32	127	25%	243	13%	n/a	n/a	n/a	n/a

Recommendations:

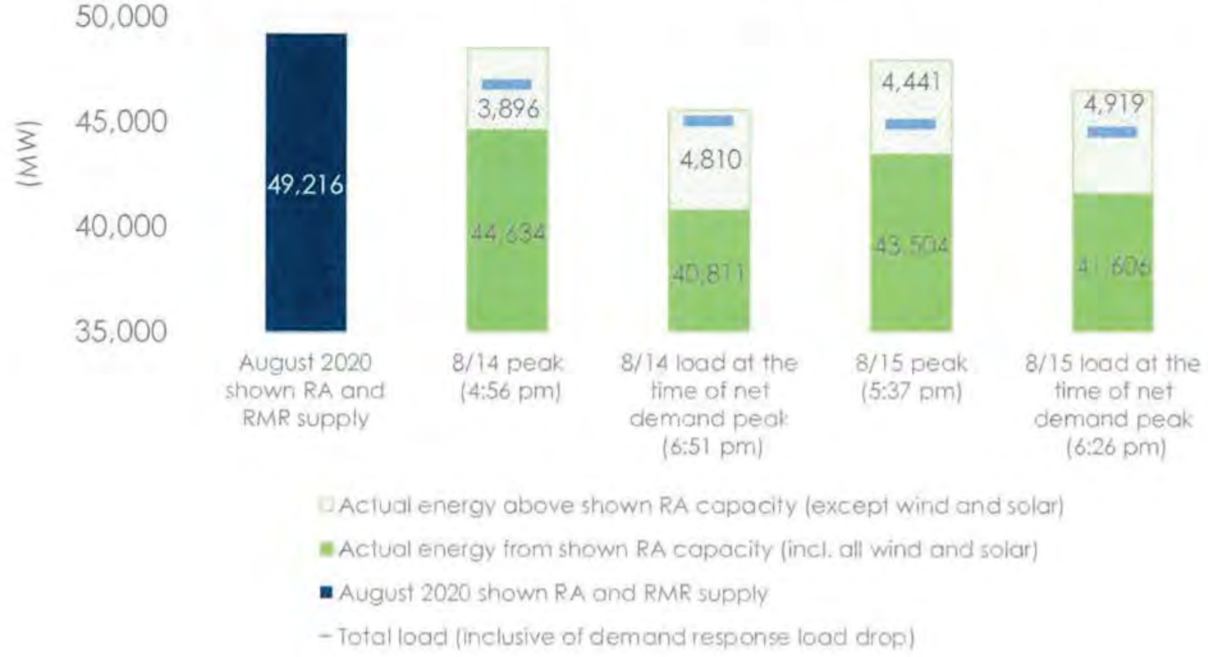
1. RDRR metered load drop approached the real-time dispatch levels; however, there is still a gap between these two levels. Further study is needed to close this gap.
2. The observed divergence between the PDR available and awarded MW in the CAISO markets indicates there was unutilized RA capacity during the critical events of the August extreme heatwave. Although a part of this divergence in the real-time markets is due to some demand response resources not being capable of responding to real-time conditions, most of this divergence may be due to bidding practices of PDR providers that reduce the likelihood of the associated demand response resources being selected in the day-ahead market, even on days with extremely high day-ahead demand forecasts. Further study is needed to examine how demand response resources are contributing to grid reliability and whether changes in RA or market requirements are warranted to align with the limitations of some demand response resources.
3. The observed divergence between awarded MW and delivered MW (load drop) requires further study and remedy. The divergence is particularly large for non-IOU PDR and suggests that a significant portion of non-IOU demand response providers may not be accurately estimating available capacity.
4. The observed deviance in the aggregate PDR bidding levels relative to the must-offer obligation based on the shown RA levels on some days (both the excess and shortfall conditions) needs further study and remedy. In particular, most PDR resources are under the 1 MW RA penalty threshold. The CAISO may assess a penalty if RA capacity is not bid into the CAISO market as required.
5. The CPUC applies "gross up" credits to demand response resources to reflect about 10% in transmission and distribution losses that demand-side resources avoid, and 15% for avoided planning reserve margin procurement for customers

who agree to drop load in grid emergencies. This results in a gap between customer-metered load drop and expected load drop based on the amount credited against RA requirements. The CAISO's BPM appeals process is attempting to address this issue constructively and collaboratively with stakeholders.

B.2.3.3 Combined Resources

Overall, the largest gap between demand and generation from the RA fleet plus resources under an RMR contract occurred during the net demand peak on August 14 and 15. Based on further analysis by the DMM, the actual production of all resources shown as RA or obligated under an RMR contract was sufficient during the peak but insufficient during the net demand peak period to meet all load, losses and spinning and non-spinning reserve obligations on August 14 and 15. Figure B.26 below compares the total August 2020 RA and RMR capacity versus actual energy production for both days during the peak and net demand peak times. The August 2020 RA capacity reflects the net qualifying capacity value shown to the CAISO on RA supply plans. The second through fourth columns in the figure show the actual energy production from RA resources and energy produced above the shown RA amount. Any IOU emergency and economic demand response dispatched during these time periods is already reflected in the reduced load. The figure shows a decrease in RA-based generation between the peak and net demand peak periods. The load markers show that a portion of load was served by energy produced above the shown RA amount for each time period. Also for simplicity, the figure does not include ancillary services awards and some RA capacity, in particular hydro generation, were used to provide that service.

Figure B.26: August 2020 Shown RA and RMR Capacity vs. August 14 and 15 Actual Energy Production (Assumes all Wind and Solar Counts as RA Supply)



Overall, actual generation from all resources was only 98% of the shown RA plus RMR allocation for August 2020 during the peak. During the net demand peak this decreases to 94%. When considering only shown RA capacity (but assuming all wind and solar generation is RA capacity), this decreases to 90% during peak and 84% during the net demand peak. The resource-specific analysis did not attempt to quantify when RA resources may have provided above or below its shown amount so actual generation from the shown RA fleet may be higher or lower than provided in this Final Analysis.

Since the Preliminary Analysis was published, a review of resource performance showed that no single generator or resource type led to the rotating outages. However, there are several changes being considered to enhance resource performance:

- Natural gas – Under very high temperatures, ambient derates are not uncommon for the natural gas fleet, and high temperatures reduce the efficiency of these resources. The CEC hosted a workshop to explore potential technology options for increasing the efficiency and flexibility of the existing natural gas power plant fleet to help meet near-term electric system reliability and the longer-term transition to renewable and zero-carbon resources.[95] Subsequently, the CPUC issued a ruling intended to get the most out the existing gas fleet in its recently opened procurement rulemaking focused on summer 2021 resources.[96] All reasonable efforts should be made to increase the efficiency of the existing fleet.

- Imports – In total, import bids received in the day-ahead market were between 40 to 50% higher than imports under RA obligations, which indicates that the CAISO was relying on imports that did not have a contract based obligation to offer into the market. In addition to the rule changes the CPUC made to the RA program with regard to imports for RA year 2021, the CPUC may consider additional changes to current import requirements.
- Hydro and pumped storage – RA hydro resources provided above their RA amounts and various hydro resources across the state managed their pumping and usage schedules to improve grid reliability. There should be increased coordination by communicating as early as possible the need for additional energy or active pump management ahead of stressed grid conditions and leverage existing plans for efficiency upgrades to improve electric reliability.
- Solar and wind – The CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour. Improvements to the RA program should account for time-dependent capabilities of intermittent resources.
- Demand response – While a significant portion of emergency demand response programs (reliability demand response resources or RDRR) provided load reductions when emergencies were called, the total amount did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO. Some, but not all of this difference, is the result of the credited amounts including a "gross up" that the CPUC applies to demand response resources consisting of approximately 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies. Additional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-

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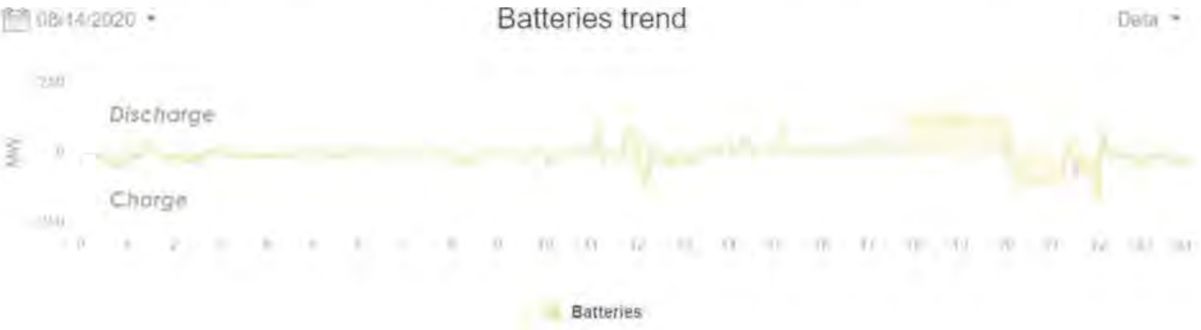
[95] See: https://www.energy.ca.gov/event/workshop/2020-12/morning-session-technology-improvements-and-process-modifications-lead and https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop

[96] CPUC, R.20-11-003, December 11, 2020 Ruling.

ahead and real-time markets, and performance of dispatched demand response.

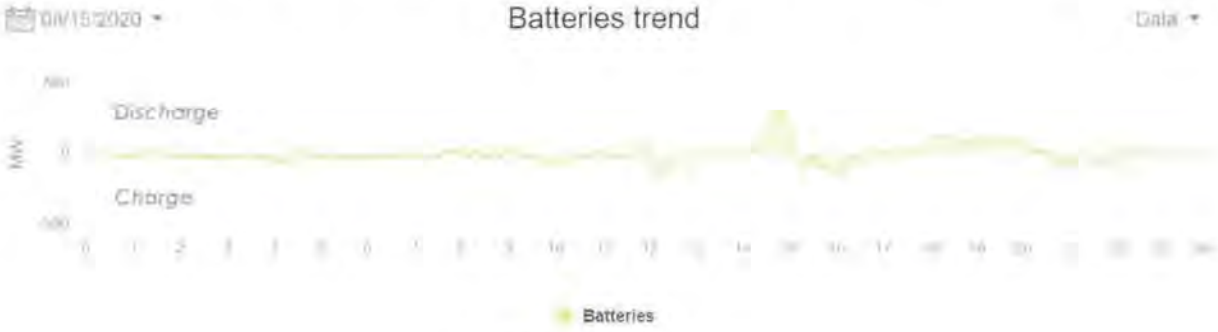
- Battery storage – During the mid-August events and in early September there were approximately 200 MW of RA battery storage resources in the CAISO market. Figure B.27 and Figure B.28 below provide illustrative snapshots of all battery performance in the CAISO market during August 14 and 15, respectively.

Figure B.27: August 14 Illustrative Battery Storage Performance



Source: CAISO

Figure B.28: August 15 Illustrative Battery Storage Performance



Source: CAISO

It is difficult to draw specific conclusions about fleet performance from such a small sample. The CAISO will continue to track and understand the collective behavior of the battery storage fleet and work with storage providers to effectively incentivize and align storage charge and discharge behavior with the reliability needs of the system. The CAISO has been working to develop enhancements to ensure that as the battery storage fleet size grows the CAISO market can effectively manage them. Several of these changes will only take effect fall 2021. In the interim, the CAISO will ensure storage resource providers understand how the CAISO expects to operate the system so that storage is available when needed to meet net peak demand challenges under stressed summer conditions.

B.3 Energy Market Practices Exacerbated the Supply Challenges Under Highly Stressed Conditions

Energy market practices encompass inputs into the energy market, how the energy market matched supply with demand, and ultimately whether the schedules from the market fully prepared the CAISO Operational staff to run the grid. Energy market practices contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid on August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by scheduling coordinators, convergence bidding masking the tight supply conditions, and the configuration of the residual unit commitment market process.

B.3.1 Demand Should Be Appropriately Scheduled in the Day-Ahead Time frame

As explained in the background in Section 2, the CAISO operates both a market the day prior to operations (*i.e.*, the day-ahead market) and a market for the day of operations (*i.e.*, the real-time market). The day-ahead market is further split into two parts: an integrated forward market (IFM) and a residual unit commitment (RUC) process. In the IFM, scheduling coordinators can bid in their load and exports at a price they are willing to pay to have their demand served. Alternatively, they can submit self-schedule for their load and exports indicating they are a price-taker. Collectively this is referred to as bid-in demand. The CAISO BAA LSEs are not obligated to self-schedule or bid-in their load in the day-ahead market. However, there are reliability consequences as the CAISO uses the day-ahead market to firm-up demand and supply schedules that are served in the real-time. In other words, the bid-in demand is cleared against bid-in supply and the outcome of the IFM is used to set the schedules for the next operating day and will determine the level of imports needed to serve load. Therefore, to secure available capacity and transmission, a load serving entity should schedule or bid in their load. Because CAISO load and exports compete for available supply, a scheduling coordinator is most likely to secure its day-ahead position through a price-taker self-schedule.

After the IFM, the RUC process starts and this is where the CAISO can commit incremental internal capacity if the CAISO forecast of CAISO demand exceeds the bid-in demand. Figure B.29 below charts the metered under- or over-scheduled load for CPUC-jurisdictional IOUs, community choice aggregators (CCAs) and energy service provider (ESP) from August 13 through 19 and from September 4 through 7. Figure B.30 charts the same for non-CPUC jurisdictional load serving entities (such as the publicly owned utilities) as well as other load serving entities that could not be easily categorized because scheduling coordinators may represent several different categories of load serving entities. Therefore, the "other" category may also include CPUC-jurisdictional entities.

Figure B.29: Day-Ahead Under- and Over-Scheduling by CPUC-Jurisdictional IOUs, CCAs, and ESPs (MW)

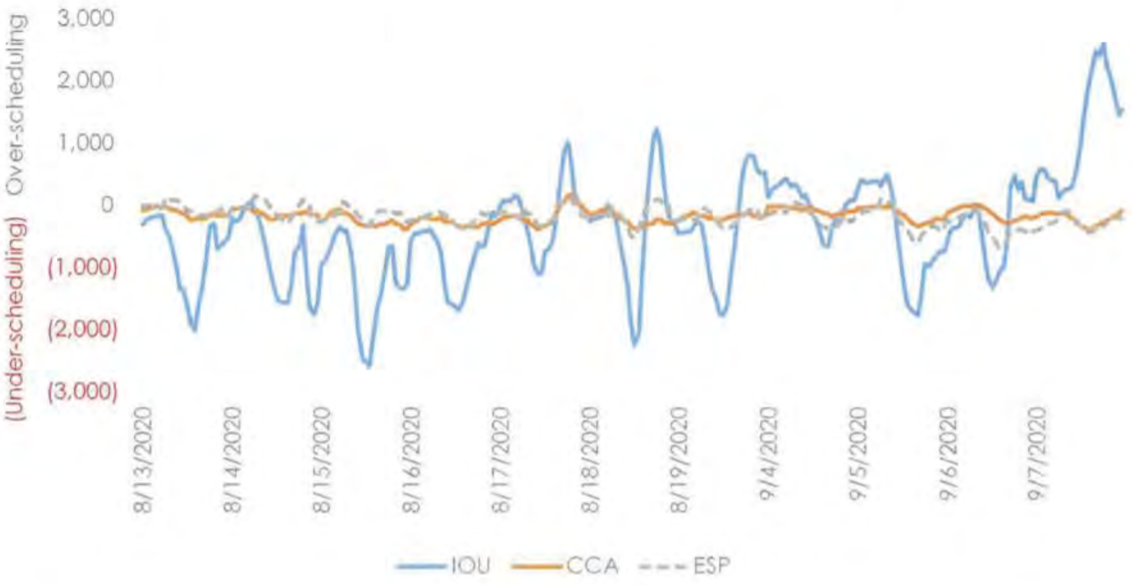
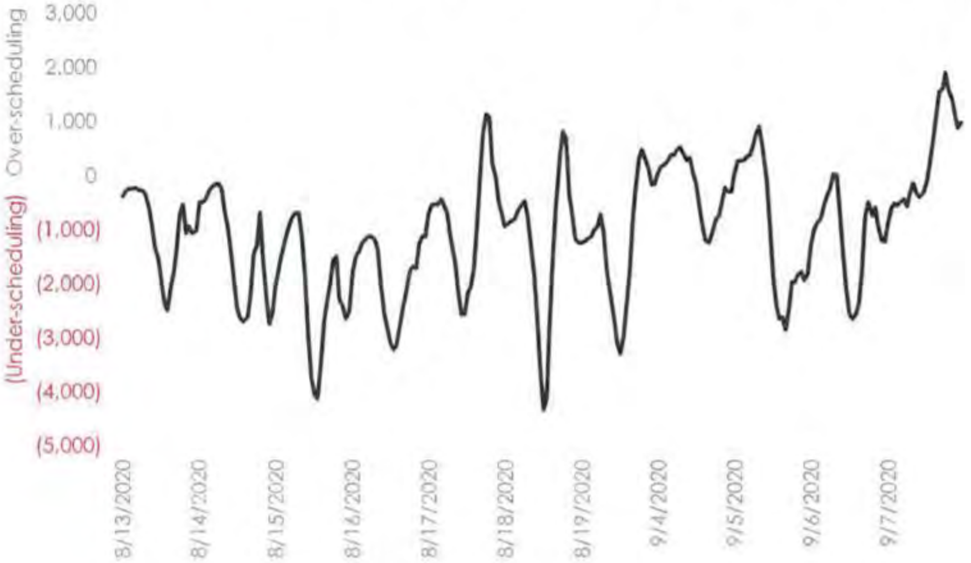


Figure B.30: Day-Ahead Under- and Over-Scheduling by Non-CPUC-Jurisdictional and Other Load Serving Entities (MW)

Figure B.31 combines all the under- and over-scheduled load amounts. This figure replaces the graphic from the Preliminary Root Cause Analysis with metered data that directly compares the bid-in load against the actual metered load to calculate the under- and over-schedule load amounts.[97]

Figure B.31: Day-Ahead Under- and Over-Scheduling for CAISO Footprint (MW)



The general trend is towards under-scheduling of load. However, from August 17 through 19 and again from September 4 through 7, the trend for IOU and non-CPUC LSE load reverses during the net demand peak hours from approximately 4 p.m. to 9 p.m. where the data suggests there is over-scheduling of load. This outcome may be due in part or entirely to the large amounts of real-time public conservation that, by comparison, makes the day-ahead bid-in load seem like over-scheduling, and to the extent this was the case, this also suggests that CCAs and ESPs under-scheduled their loads to a higher degree than the charts reflect for these dates. This pattern is most pronounced on Sunday, September 6 and Monday, September 7 over the Labor Day weekend heat wave.

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[97] This direct comparison has the benefit of eliminating load differences beyond the LSEs' control such as pumping load.

Figure B.32 through Figure B.34 repeat the graphs above but on a percent of actual load basis to facilitate comparison between the groups of load serving entities.

Figure B.32: Day-Ahead Under- and Over-Scheduling by CPUC-Jurisdictional IOUs, CCAs, and ESPs (as % of actual)

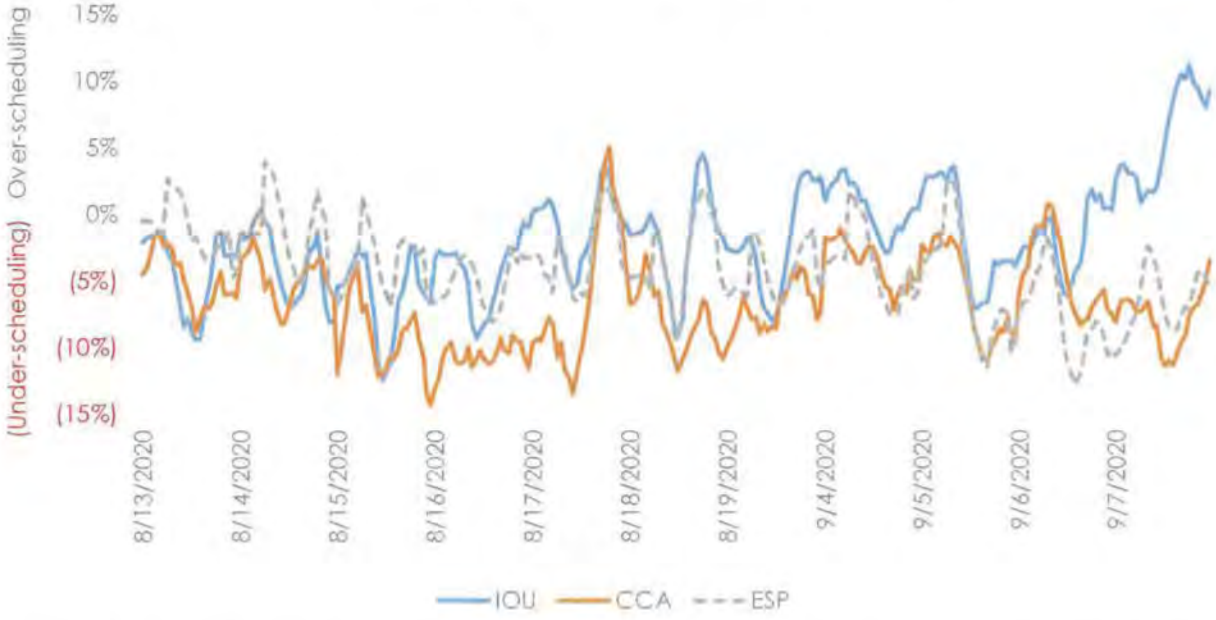

Figure B.33: Day-Ahead Under- and Over-Scheduling by Non-CPUC-Jurisdictional and Other Load Serving Entities (as % of actual)

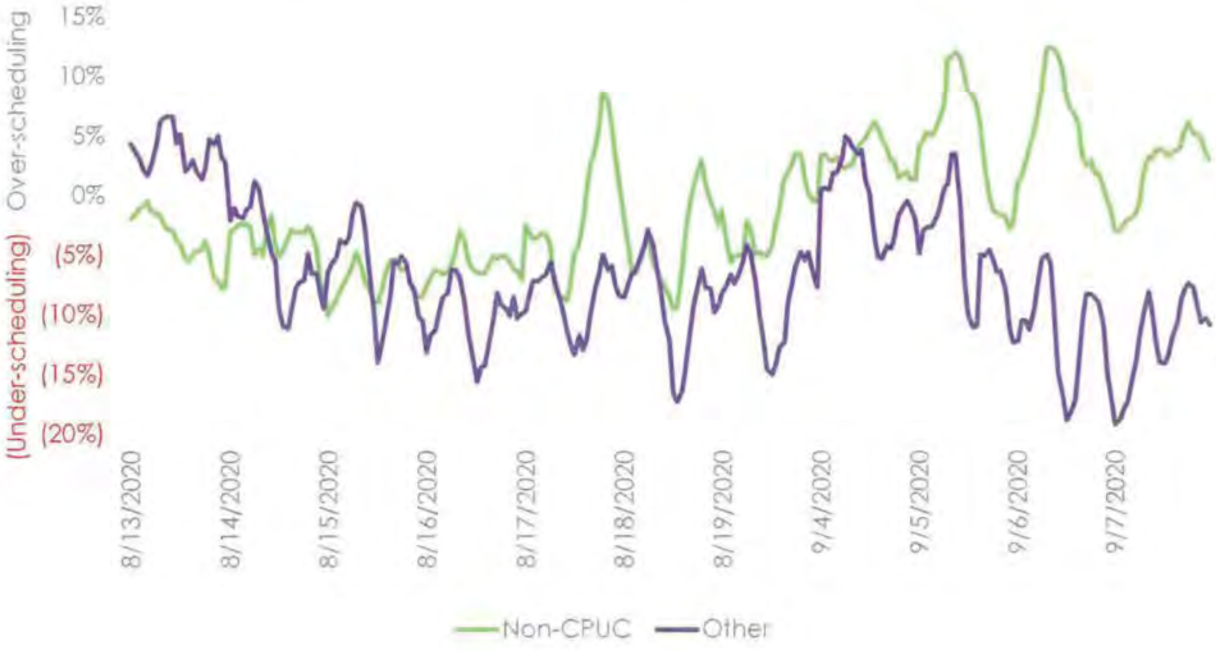

Figure B.34: Day-Ahead Under- and Over-Scheduling for CAISO Footprint (as % of actual)

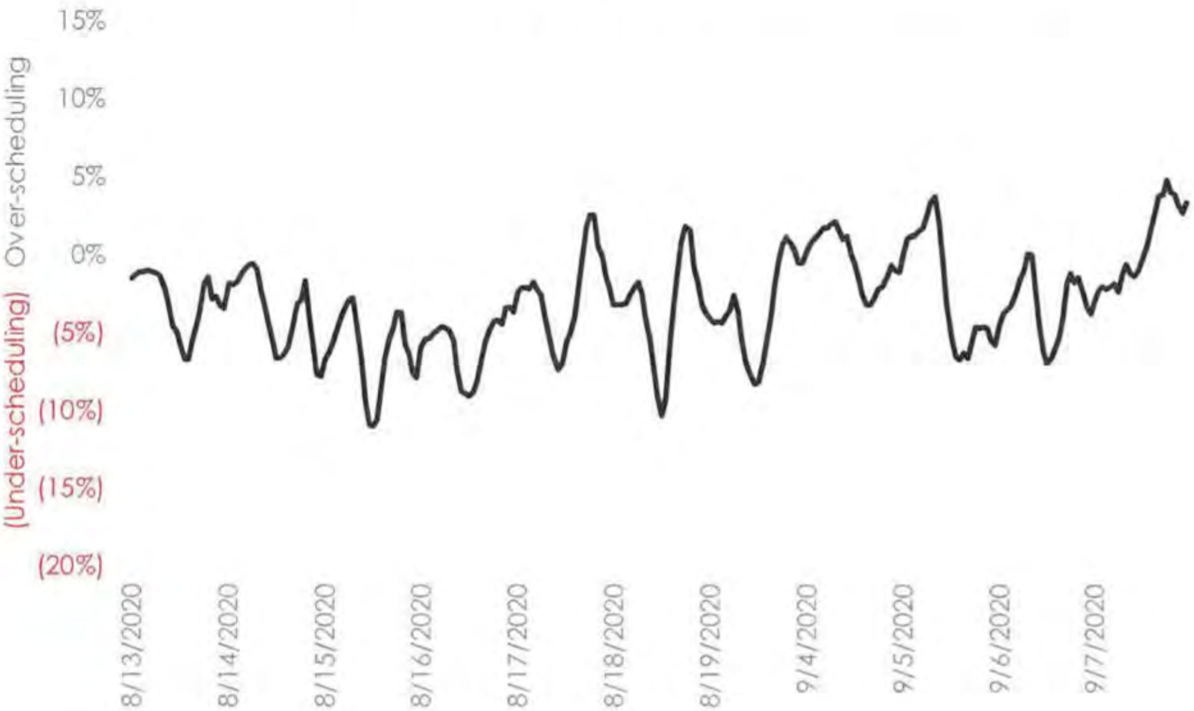

Table B.4 below summarizes the MW and percent of actual of load under- or over-scheduled on August 14 and 15 during the peak and net load peak hours.

Table B.4: Comparison of Under- and Over-Scheduling of Load on August 14 and 15 (Under-Scheduling Reflected as Negative Number)

	IOU	CCA	ESP	Non-CPUC	Other	Total
8/14 (MW)						
Peak	(1,288)	(153)	(206)	(131)	(385)	(2,164)
Net demand peak	(664)	(146)	8	(134)	(336)	(1,272)
8/15 (MW)						
Peak	(1,147)	(297)	(90)	(223)	(266)	(2,023)
Net demand peak	(671)	(282)	(118)	(242)	(234)	(1,547)
8/14 (as % of actual)						
Peak	(5%)	(4%)	(4%)	(3%)	(8%)	(5%)
Net demand peak	(3%)	(4%)	0%	(3%)	(7%)	(3%)
8/15 (as % of actual)						
Peak	(4%)	(8%)	(2%)	(6%)	(6%)	(5%)
Net demand peak	(3%)	(8%)	(2%)	(6%)	(5%)	(4%)

Under-scheduling the level of demand impacts the level of supply and demand, including imports and exports, cleared in the IFM and scheduled in the day-ahead time frame. To better understand why under-scheduling may occur, the CAISO surveyed scheduling coordinators representing 75% of the peak load in the CAISO footprint on August 14, including the three major IOUs. Generally, scheduling coordinators' primary goal was to develop the most accurate forecast possible to bid into the CAISO's day-ahead market. However, the survey uncovered the following challenges:

- Data quality and availability - Load forecasts rely on actual load information. LSEs rely on different sources with different timelines to acquire historical usage information. Although smart meter data is available to some extent and under certain conditions, LSEs largely rely on metered data to obtain higher quality usage data, which is available only two months after the trade date. Data available at an earlier time frame is much less accurate and sometimes incomplete.
- Extreme weather conditions - Load forecasting models are based on weather variables such as temperature, cloud cover, and humidity. Under extreme weather conditions, such as the mid-August extreme heat wave, models struggle to accurately forecast load. This has been exacerbated by the need to accurately forecast the growth of behind-the-meter resources and their generation patterns.
- COVID-19 and shelter-in-place impacts - The unprecedented impacts of COVID-19 and the shelter-in-place orders were a major challenge to forecasting since there is no historical or similar historical data to model.
- Footprint changes - IOUs historically forecast load based on their distribution utility footprint as a whole and then separate the subset of load for which they are responsible for to develop a load forecast. The IOUs have identified the evolution of that footprint change as a challenge to forecasting accuracy.

The CAISO honors self-schedules so long as there is sufficient generation and transmission capacity to support those schedules. Although this is done infrequently, if there is a shortage of supply, or transmission constraints are binding, the IFM will curtail self-schedules to clear the market. When such curtailments are necessary, the CAISO protects these load self-schedules with high priority.[98]

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[98] Those using Existing Transmission Contract (ETC) and Transmission Ownership Rights (TOR) may also schedule balanced source (generation, imports) and sinks (load and exports) pursuant to their rights to receive higher self-schedule priority.

Scheduling coordinators may also self-schedule exports in the IFM. Export self-schedules will receive equal or lower priority than CAISO self-scheduled load depending whether they are explicitly supported by capacity that has not been designated as RA capacity when scheduled into the day-ahead market. If the scheduling coordinator identifies in its export self-schedule that it is explicitly supported by capacity that is not designated as RA capacity, that export self-schedule will receive the same priority as internal self-scheduled load. All other self-scheduled exports, *i.e.*, any export self-schedules that do not identify capacity that has not been designated as RA capacity will have a lower priority than internal load. If there is a shortage of supply or transmission constraints are binding, these lower priority export self-schedules will only clear the IFM if sufficient supply is available after serving self-scheduled CAISO load and the higher priority exports.

In this way, even though entities scheduling exports cannot tie the export to RA capacity, the CAISO ensures the IFM curtails exports that may be served from RA resources first to the benefit of internal CAISO load.

CAISO load cannot benefit from the higher protection for their day-ahead schedules if scheduling coordinators do not actually submit self-schedules to the day-ahead market to cover their expected load. Therefore, if CAISO load under-schedules in the day-ahead market, that is, it does not submit sufficient self-schedules or bids in the day-ahead market to cover the amount of load that actually materializes in the real-time market, export schedules will be cleared and will secure a firmer position in the day-ahead market.

Figure B.35 below shows the amount of total day-ahead scheduled exports[99] cleared for August 13 through 15 relative to the amount of capacity that was in the market but was not associated with capacity that was not shown to be RA capacity. Unlike the prior analyses, this export analysis is based on a deeper dive that specifically tracks resources shown for RA, rather than a simplifying assumption applied to wind and solar resources. For this export analysis, a resource with any amount of shown RA capacity is fully categorized as RA. The analysis finds that during the Stage 3 Emergencies there were more non-RA resources than exports.

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[99] Net of energy wheeled through the CAISO system.

Figure B.35: Comparison of Day-Ahead Non-RA Cleared Supply vs. Total Day-Ahead Scheduled Exports

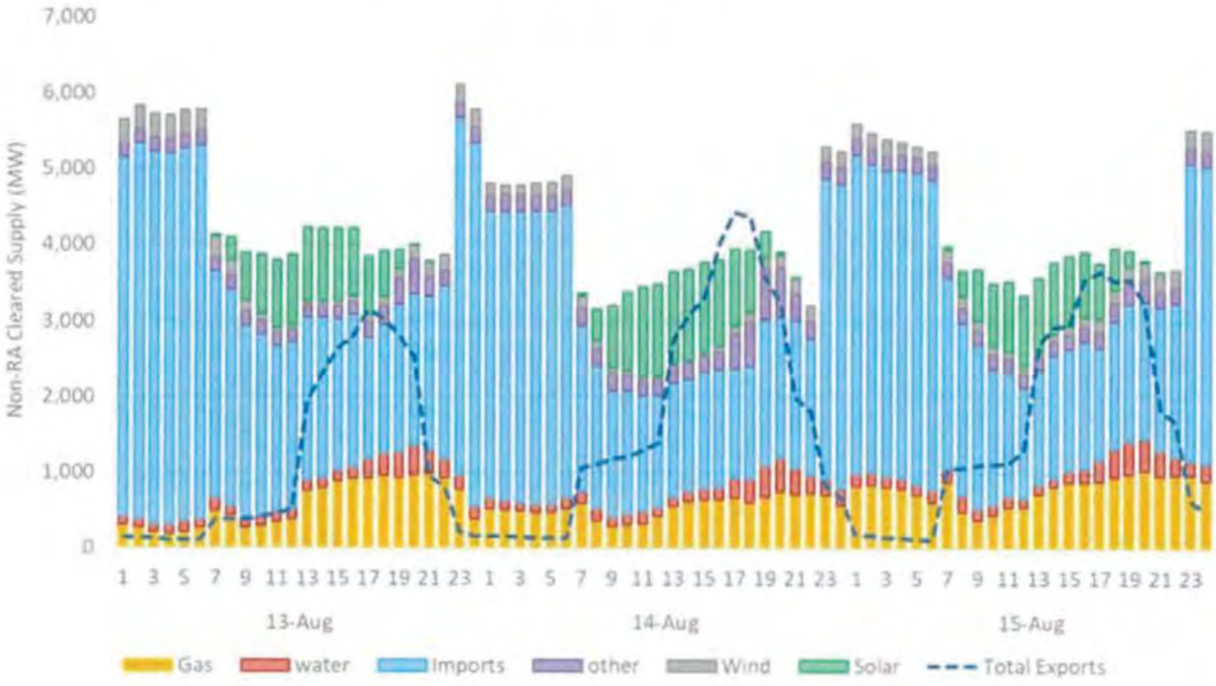


Figure B.36 below shows the breakdown of export types (reflected as the dotted line in the prior figure) from: economical bids, priority (PT), lower priority (LPT) and other self-schedule types for day-ahead scheduled exports.

Figure B.36: Total Day-Ahead Scheduled Exports by Category

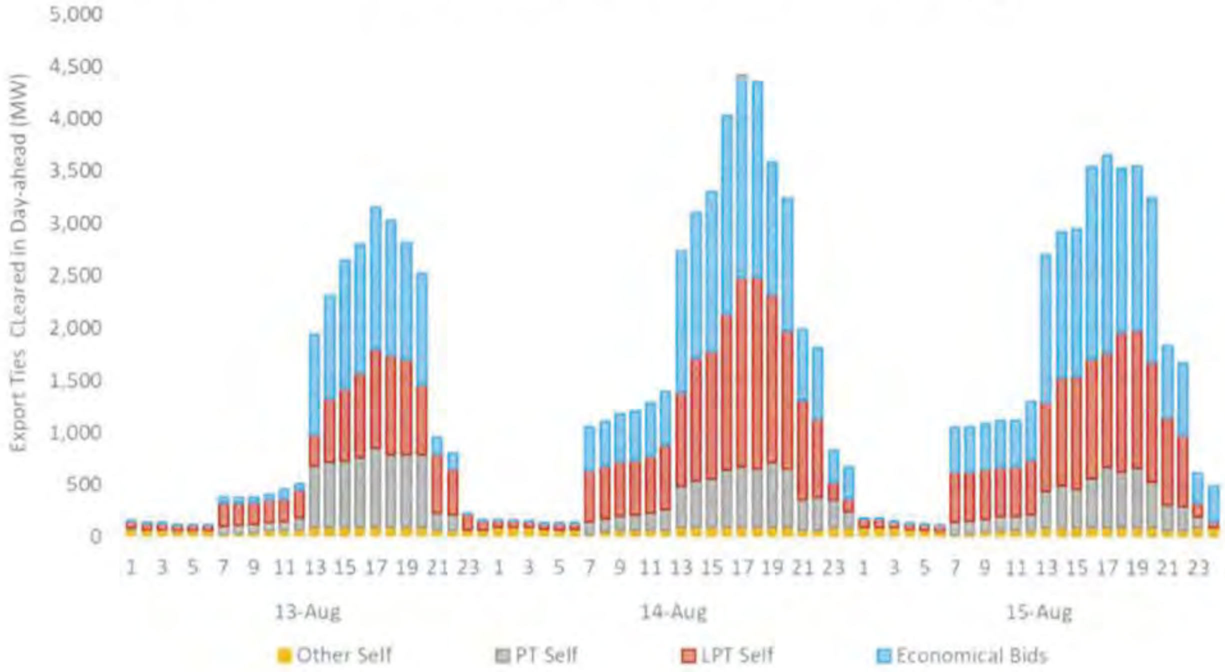


Figure B.37 below provides a more comprehensive comparison of the day-ahead and real-time imports and exports during August 13 through 15. Figure B.37 shows all the intertie schedules across four different time frames: integrated forward market (IFM); residual unit commitment (RUC); hour-ahead scheduling process (HASP); and the actual import or export. Imports are shown as positive numbers while exports are negative numbers. Both IFM and RUC are processes in the real-time while the HASP is a specific real-time scheduling process mostly used by imported and exported energy. The Stage 3 durations for both August 14 and 15 are shown in the shaded areas. The figure shows that when CAISO declared a Stage 3, HASP and actual imports added approximately 1,500 MW to the IFM and RUC schedules on August 14 and by approximately 1,400 MW on August 15.

Figure B.37: Day-Ahead and Real-Time Imports and Exports During August 13-15

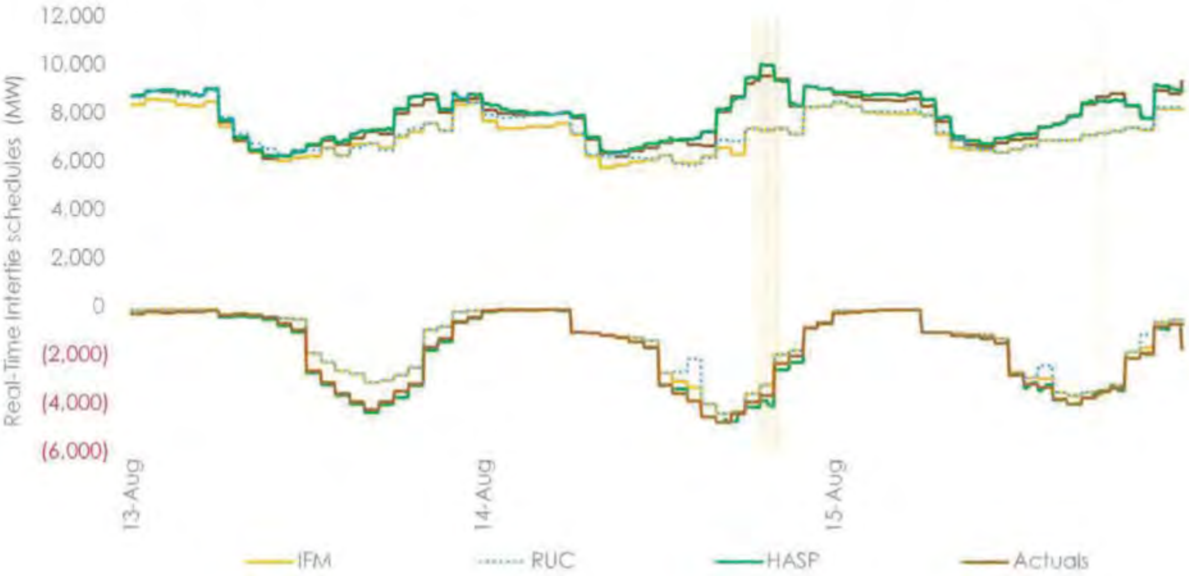
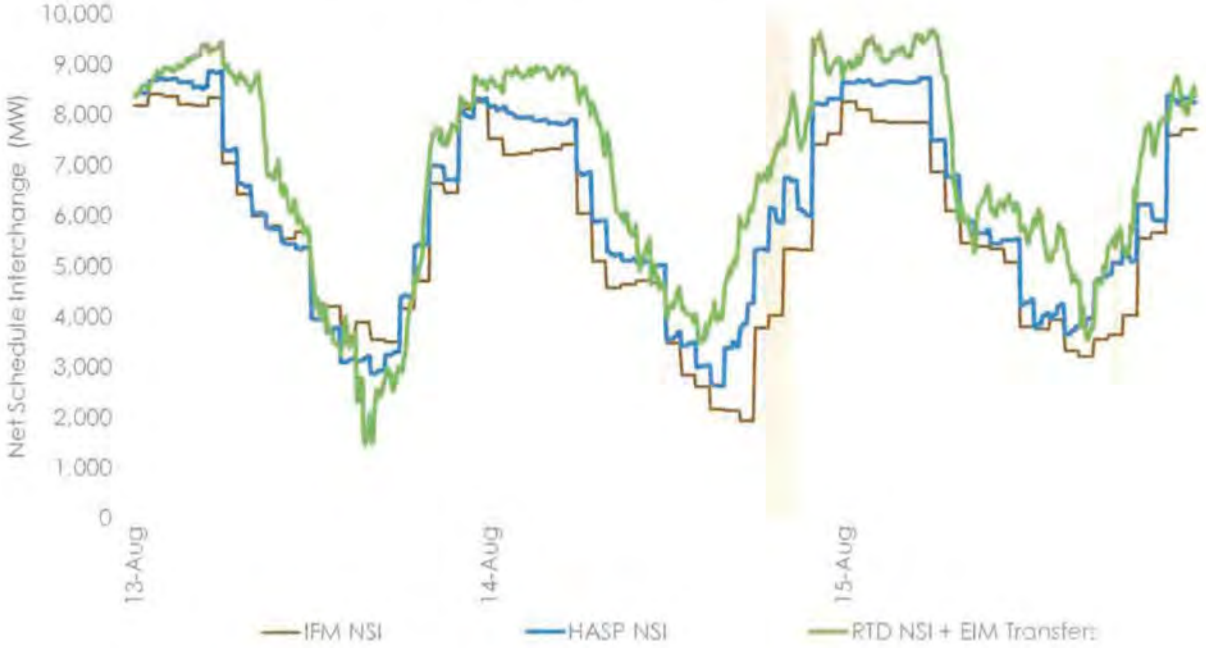


Figure B.38 shows the net of all imports and exports, now including Energy Imbalance Market (EIM) transfers in addition to the real-time dispatch (RTD) net scheduled interchange (NSI). During August 13 through 15, the CAISO was a net importer of energy across all hours of both the day-ahead and real-time markets. EIM transfers added another 1,500 MW of imports when the CAISO declared a Stage 3 on August 14 and 600 MW on August 15. In total, real-time imports increased by 3,000 MW and 2,000 MW on August 14 and 15, respectively, when the CAISO declared a Stage 3. These real-time imports reversed most of the economic and low priority exports that cleared the day-ahead market.

Figure B.38: Net Imports During August 13-15



B.3.2 Convergence Bidding Masked Tight Supply Conditions

Scheduling coordinators can also submit convergence bids for supply and demand at internal locations on the CAISO grid. Convergence bids are financial positions in the IFM that automatically liquidate at the real-time price.[100] As the name suggests, convergence bidding should allow bidders to converge or moderate prices between the day-ahead and real-time markets. Convergence bids cannot be price-takers and therefore they are only considered to the extent there are sufficient supply bids to clear the demand and are not protected from curtailment as are self-scheduled CAISO load and exports. However, if CAISO load does not submit sufficient bids or self-schedules in the day-ahead market, the convergence supply bids will influence how much load and exports are scheduled in the day-ahead market. Convergence supply bids may support bid-in load and exports and may avoid triggering the need to curtail self-schedules. In addition, convergence demand bids may clear supply schedules for load that materializes in the real-time. Convergence demand bids do not guarantee that the specific load schedule will be served in the real-time, but they may facilitate the scheduling of physical generation to serve actual demand in the real-time.

Figure B.39 illustrates how under-scheduling of CAISO load when there is a shortage of supply can result in lower-priority self-scheduled exports clearing the market compared

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[100] Convergence bidding is not permitted at the interties. Therefore, only physical export bids are permitted.

to what would have cleared had load scheduled closer to the actual load level. In contrast, Figure B.40 illustrates how under-scheduled load has no impact on the amount of cleared self-scheduled exports when there is sufficient supply. Although the cleared price could be lower with less load schedule the amount of self-scheduled exports that clear is the same.

Figure B.39: Illustrative Example of Impact of Under-Scheduled Load Under Supply Scarcity

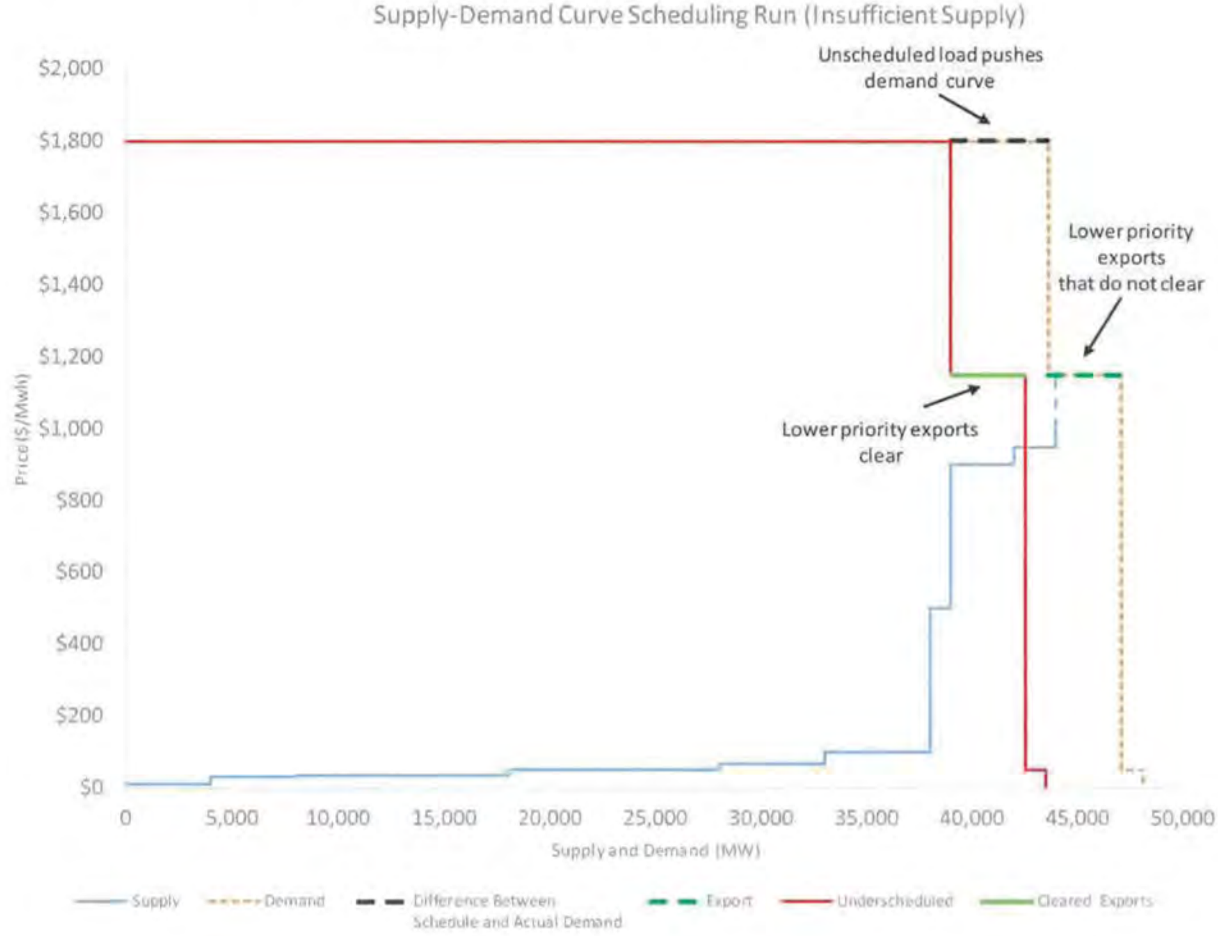
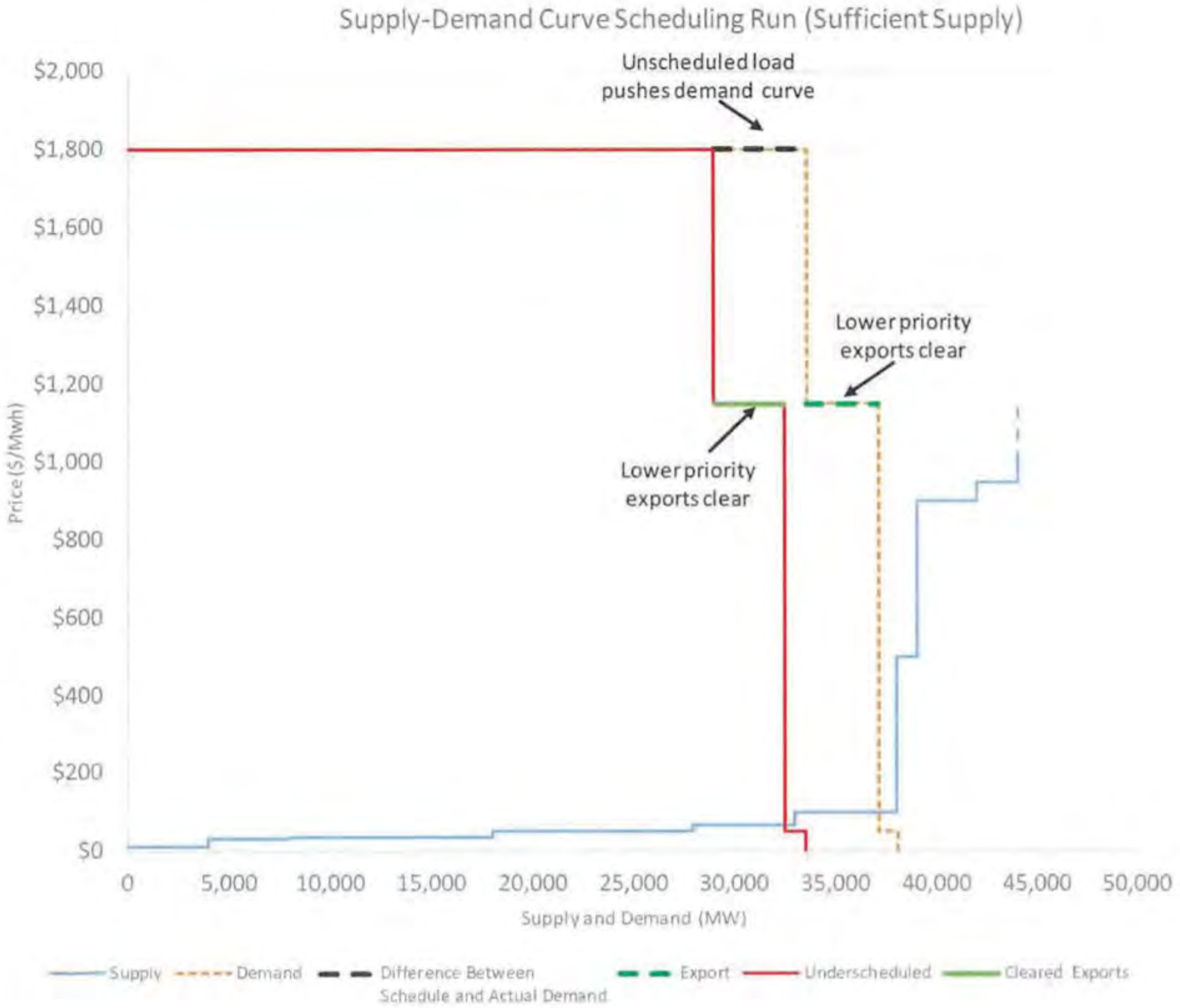
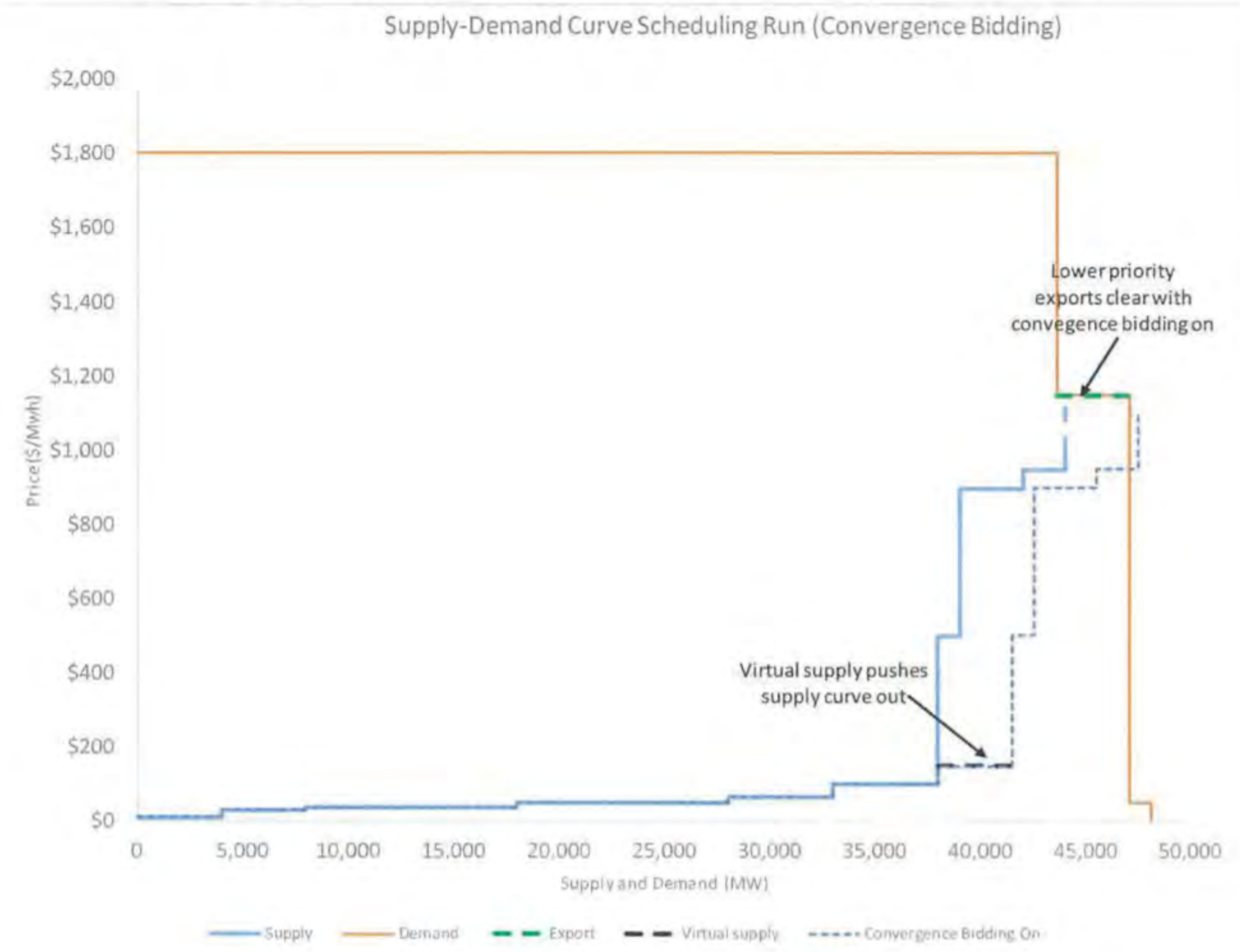


Figure B.40: Illustrative Example of Impact of Under-Scheduled Load Under Supply Sufficiency



Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in converging or moderating prices between the day-ahead and real-time market conditions and aligning loads and resources for the next day. Similar to under-scheduled load, during conditions in which physical supply is scarce, cleared virtual supply can mask physical supply shortages and allow more demand including low-priority exports to clear than what can be physically supported (refer to Figure B.41 illustration).

Figure B.41: Illustrative Example of Impact of Convergence Bidding



For the August 14 and 15 trading days, the IFM solution was able to clear the CAISO load and self-scheduled exports, regardless of their priorities. The IFM for those days cleared without having curtailments, in part because load under-scheduled based on the day-ahead forecast of demand, and in part because financial supply side positions taken by convergence bids facilitated the clearing of all demand and exports. This combination of factors created the ability for the day-ahead market to clear more exports than were ultimately actually physically supportable.

After observing this interaction in the day-ahead market, to ensure the CAISO could contiunue to manage the system reliabily, on August 16 the CAISO temporarly suspended convergence bidding for trade days August 18 through August 21. The CAISO reinstated convergence bidding after demand conditions no longer appeared to pose the same risk in the day-ahead market.

B.3.3 Residual Unit Commitment Process Changes

The day-ahead RUC process runs after the IFM and is also part of the day-ahead market. The RUC inputs differ from the output of the IFM in several key ways to ensure the CAISO can produce a reliable operating plan for the next operating day. First, the CAISO load cleared in the IFM is replaced by the CAISO forecast of CAISO demand, which does not include exports. Second, the wind and solar schedules cleared in the IFM are replaced by CAISO forecast production for wind and solar resources. Lastly, the virtual supply and demand cleared in the IFM are removed. Under normal conditions when there is sufficient supply to commit, RUC will commit additional resource capacity to ensure forecast load can be served in the real-time. However, in rare circumstances that there is insufficient supply to commit, the RUC process must address the supply insufficiency. There are two passes in the RUC process: a scheduling run pass and a pricing run pass. The RUC scheduling run pass is designed to address any unresolved constraint using an intricate but prescribed set of relative priorities for how to relax the constraint or curtail schedules previously determined in the IFM. Prior to the implementation of Pricing Inconsistency Market Enhancements (PIME), the scheduling run results were the source of final RUC awards and schedules. The pricing run was intended to produce prices that align both bid cap of $1,000 as well the scheduling run results.[101] However, after the implementation of PIME both IFM and RUC were redirected to use pricing run results for the source of both schedules and prices.

As discussed above, under normal supply and transmission conditions, the CAISO does not expect RUC to have to curtail day-ahead schedules cleared in the IFM. The RUC also does not dispatch down supply resources scheduled in the IFM. However, the CAISO enforces both power balance and intertie scheduling constraints in the RUC to ensure the schedules produced in the IFM are physically feasible. The power balance constraint ensures that forecast load can be met and the intertie constraint ensures that the net of physical imports and physical exports schedules on each intertie are less than or equal to the scheduling limit at the intertie, in the applicable direction. Through these RUC constraints the CAISO determines what portion of the day-ahead schedules are physically feasible, and which portion that market participants should tag when the E-Tag is submitted in the day-ahead.

After experiencing the August 14 and 15 events, the CAISO reviewed the results of the day-ahead market for those trading days more closely and observed that rather than

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[101] In 2014, the CAISO implemented pricing functionality enhancements to address observed inconsistencies between scheduling run schedules and pricing run prices. The enhancement is referred to as Pricing Inconsistency Market Enhancement (PIME). Among other things, PIME changed from using schedules from the scheduling run to using schedules produced by the pricing run.

reducing exports that cleared the IFM that were not feasible, the RUC pricing run solution relaxed the system power balance constraint. However, in the RUC scheduling run pass, IFM exports were relaxed based on their order of priority prior to relaxing the power balance constraint. The CAISO had previously applied the PIME to the RUC as a matter of applying PIME to all its markets. The PIME in the other markets is necessary because it is necessary to have consistency between energy schedules and prices. The lack of energy schedules in RUC obviates the need for PIME in the RUC process. As a result, starting from the day-ahead market for September 5, 2020, the CAISO stopped applying the PIME functionality to RUC process, which enabled it to use the scheduling run results for RUC schedules and awards instead of the pricing run results.

After the day-ahead market and leading up to the real-time market, the CAISO protects the outcome of the schedules awarded in the day-ahead market as inputs into the real-time market so as to ensure that cleared day-ahead schedules are honored and treated as "firm" in the real-time. This is accomplished by providing these schedules a higher priority than new schedules that were not scheduled and cleared in the day-ahead market and now being considered in the real-time market.[102] Schedules that cleared the day-ahead market are protected equally in the real-time market process, regardless of how they were submitted to the real-time market.

In the real-time market, the CAISO again allows participants to submit export bids and supply bids. However, load cannot submit bids to the real-time market and the CAISO clears the market based on the CAISO forecast of CAISO demand, at the same time the market solution considers clears export schedules and bids. Like the day-ahead market, participants can submit export self-schedules and the priorities for export schedules are the same as the day-ahead market. That is, the newly submitted real-time export self-schedules that are supported by non-RA capacity will have the same priority as CAISO load. However, any new exports that did not clear day-ahead market and are not explicitly supported by non-RA capacity will have a lower priority as the CAISO relies on that generation to serve its load reliably.

In addition to potentially curtailing exports through the CAISO markets, the CAISO operators may curtail export or import schedules for purposes of reliable operations. However, there are significant operational matters that need careful consideration before curtailing cleared and tagged exports in real-time. For such curtailments to be

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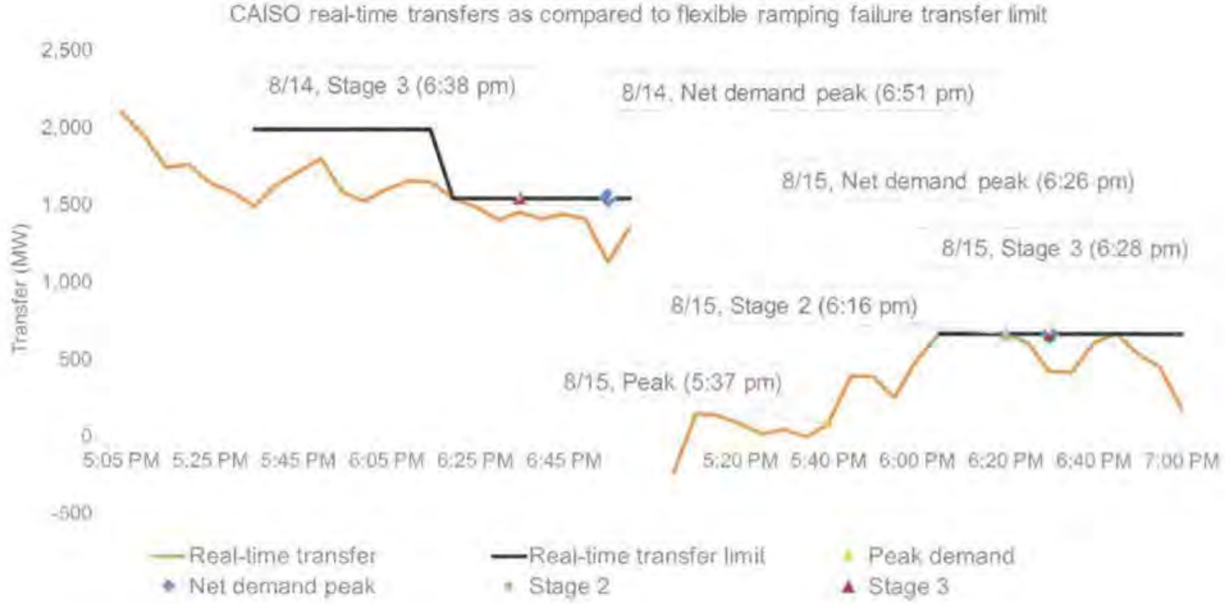
[102] Until September 5, 2020, the CAISO was protecting the full day-ahead schedule as cleared through the day-ahead IFM process. The CAISO modified its process to now only protect what is determined to be physically feasible through the day-ahead RUC process. See discussion of Business Practice Manual change (PRR 1282) in: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf

even be implemented effectively, information about the individual exports and relative priorities would have to be readily available to the operators. Furthermore, those relying on such exports need to be made aware of the potential risk of such exports being curtailed in advance so that they can take measures to avoid being put into an emergency condition upon loss of such exports. Absent such operator information or neighboring BAAs being aware of curtailments in a timely manner, curtailing cleared and tagged exports during quickly emergent real-time conditions would not be consistent with coordinated and good utility practices. Furthermore, the curtailment of the export may not be effective in addressing the reliability issue. In other cases, cutting the exports may further exacerbate conditions as curtailment of an export may result in the cutting of an import at the applicable intertie because the interchange was permissible only due to counterflow provided by the export. Finally, when the CAISO is in the position of relying on emergency energy from its neighbors, the threat of an export curtailment to another BAAs when conditions are constrained throughout the system may prevent access to emergency energy either at that time or in the future.

B.3.4 Energy Imbalance Market

During August 14 and 15 the CAISO BAA failed the flexible ramping sufficiency test in some intervals during peak hours. This test is a feature of the western Energy Imbalance Market (EIM) and was designed to ensure that each participating member procured enough resources to meet its own ramping needs. If a BAA participating in the EIM passes the resource sufficiency evaluation, it will have access to additional EIM transfers to meet its load for the next operating hour. If the EIM Entity fails the resource sufficiency evaluation for the next operating hour, then the BAA that failed the test will only be allowed transfers during that hour up to the amount transfers from the prior hour in the direction of the failure. The CAISO is subject to the flexible ramping sufficiency test like all other BAAs in the EIM. On August 14 and 15, the CAISO failed for less than two hours on each day and a cap was imposed on the transfer limit into the CAISO. Transfers are still allowed to occur up to the most recent transfer level but not beyond it. On those days the failure of the flexible ramping sufficiency test did not negatively impact the CAISO's ability to obtain EIM resources because the transfers were largely below the cap. Figure B.42 below shows that during critical times when the Stage 3 Emergencies were declared, the actual real-time transfers into the CAISO were below the cap imposed by the failures. This means that even with no failures there was already limited energy available for additional transfers. On August 15 there was a 20 minute period when the transfer limit was binding (*i.e.*, when the transfer of energy was at the cap), which overlapped with the declaration of a Stage 2 Emergency, but real-time transfers quickly fell after that and was below the cap when the Stage 3 Emergency was declared. The figure also shows that the CAISO did utilize and benefit from voluntary EIM transfers when available.

Figure B.42: CAISO EIM Real-Time Transfers as Compared to Flexible Ramping Sufficiency Cap



The CAISO's real-time market and operations helped to significantly reduce the interactive effects of load under-scheduling, convergence bidding, and the impact on the RUC process in the day-ahead market. As discussed above, the CAISO market and operations were able to attract imports including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other BAs to reduce the impact of these challenges. However, actual supply and demand conditions continued to diverge from market and emergency plans such that even with the additional real-time imports, the CAISO could not maintain required contingency reserves as the net demand peak approached on August 14 and 15.

I/A

Generator Interconnection Facilities Study Report

Wake County, NC
100.0 MW Battery Storage Plant
Queue #479

Revision 1: Updated due to prior-queued withdrawals.

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PROGRESS

February 4, 2022
Duke Energy Progress
Transmission Department

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1 PURPOSE

The purpose of this Facilities Study is to assess the impacts of a generator interconnection request on the reliability of the Duke Energy Progress (DEP) transmission system with respect to power flow and short circuit. Estimates of the cost and time required to interconnect the generation as well as to resolve the impacts as determined in this analysis are also included. The DEP internal system analysis consists of an evaluation of the internal DEP transmission system utilizing documented transmission planning criteria. The requests are described in Table 1 below.

Table 1: Interconnection Requests

DEP Generator Interconnection Queue No.	MW	Requested In-Service Date	County	Interconnection Facility
479	100.0 storage	06/30/2021	Wake County, NC	230 kV yard at Wake 500 kV Substation

2 ASSUMPTIONS

The following Facilities Study results are from the DEP internal power flow models that reflect specific conditions of the DEP system at points in time consistent with the generator interconnection requests being evaluated. The cases include the most recent information for load, generation, transmission, interchange, and other pertinent data necessary for analysis. Future years may include transmission, generation, and interchange modifications that are not budgeted and for which no firm commitments have been made. Further, DEP retains the right to make modifications to modeling cases as needed if additional information is available or if specific scenarios necessitate changes. For the systems surrounding DEP, data is based on the ERAG MMWG model. The suitability of the model for use by others is the sole responsibility of the user. Prior queued generator interconnection requests were considered in this analysis.

The results of this analysis are based on Interconnection Customer's queue requests including generation equipment data provided. If the facility technical data or interconnection points to the transmission system change, the results of this analysis may need to be reevaluated.

This study was based on the following assumptions:

- CUSTOMER would construct, own and operate the electrical infrastructure that would connect their generation to DEP's facilities, including any step up transformers and lines from the generators, but excluding the circuit breaker in the new breaker station where applicable.

3 RESULTS

3.1 Power-flow Analysis Results

3.1.1 Generator/Discharging

Facilities that may require upgrade within the first three to five years following the in-service date are identified. Based on projected load growth on the DEP transmission system, facilities of concern are those with post-contingency loadings of 95% or greater of their thermal rating and low voltage of 92% and below, for the requested in-service year or the in-service year of a higher queued request. The identification of these facilities is crucial due to the construction lead times necessary for certain system upgrades. This process will ensure that appropriate focus is given to these problem areas to investigate whether construction of upgrade projects is achievable to accommodate the requested interconnection service.

The subject queue request, as well as nearby existing and prior-queued generation and their assigned transmission upgrades, were modeled and assumed to be operating at full output. All relevant contingency categories from NERC Standard TPL-001-4 have been analyzed in this study.

While generating/discharging, contingency analysis study results show that interconnection of these generation facilities **does not result in new thermal overloads** on the DEP system (Table 2). In addition, the requested interconnection **does not contribute to thermal overloads** assigned to prior requests (Table 3). The current request is not dependent on any upgrades in the utility transmission plan (Table 4).

Table 2: Network Upgrades Assigned to This Request - Discharging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
	None					

Table 3: Contingent Network Upgrades Assigned to Prior Requests - Discharging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
	None					

Table 4: Contingent Network Upgrades in the Utility Transmission Plan - Discharging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Utility	None					

These results are dependent on assumptions regarding prior-queued interconnection requests. If any prior-queued requests drop out of the queue, these results **may change significantly**.

3.1.2 Load/Charging

DEP studied charging of the battery at the full requested 100 MW at the most stressful times of summer and winter peak load conditions, including all relevant contingency categories from NERC Standard TPL-001-4. Charging this battery storage plant **does cause new thermal overloads** on the DEP system (Table 5). Charging the battery does not contribute to any thermal overloads assigned to a prior interconnection request (Table 6). Charging is not dependent on any upgrades in the utility transmission plan (Table 7).

For charging under Network Resource Interconnection Service (NRIS), this request is responsible for the upgrades in Table 5. However, for Energy Resource Interconnection Service (ERIS), this request would not require those upgrades. ERIS service would require only the basic interconnection upgrades summarized in section 3.7.

Table 5: Network Upgrades Assigned to This Request – NRIS Charging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Q479	Erwin - Fayetteville 115kV line	SREMC Wade-Beard	6.8	Reconductor to 3-1590 ACSR	20.0	4
Q479	Cape Fear - West End 230kV line	West End-CEMC Center Ch.-Sanford Garden St Tap-Sanford US1	26.65	Reconductor to 6-1590 ACSR	84.5	4
	Total				**104.5**	

Table 6: Contingent Network Upgrades Assigned to Prior Requests - Charging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
	None					

Table 7: Contingent Network Upgrades in the Utility Transmission Plan - Charging

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Utility	None					

These results are dependent on assumptions regarding prior-queued interconnection requests. If any prior-queued requests drop out of the queue, these results **may change significantly**.

3.2 Stability Analysis Results

A stability analysis was performed to determine the impact of the proposed generation additions on the DEP transmission system and other nearby generation. The subject queue request, as well as nearby existing and prior-queued generation, were modeled and assumed to be operating at full output. **Stability was tested in both full discharging and full charging modes.**

The proposed resource was modeled considering the specific layout and number of inverters (140 TMEIC BSU-L0840GR, 117.6 MVA) provided by the requester. The model included a single lumped equivalent generator to represent the inverters, with an inverter transformer (6.2%Z at 4200 kVA x 28, 117.6 MVA total), and equivalent MV and LV collector impedances. The interconnection to the DEP transmission system was via a single substation transformer (8.0%Z at 66/88/110 MVA), based on data provided by the requester.

A representative set of faults was simulated to determine if there would be any adverse impact to the transmission system as a result of the proposed generation. The ability of the plant to ride through the voltage depressions resulting from the faults was also verified, based on the model parameters provided by the Customer.

The inverters tripped offline for numerous transmission faults for which they should not. The requester will need to set inverter fault ride-through settings to follow the requirements of NERC Standard PRC-024, including interpretations provided by the NERC IRPTF in published NERC Alerts. Instantaneous tripping should be avoided when at all possible, and the ride through region should be set as large as possible. As part of this requirement, the inverters must continue to inject reactive current during the fault ride-through period. Momentary Cessation is not to be used in new inverter-based generation plants.

The stability evaluation **did not** identify any stability problems. Except as described above, all generators stayed on-line and stable for all simulated faults. If the Customer data changes from that provided, these results will need to be reevaluated.

3.3 Power Factor Requirements

DEP's Large Generator Interconnection Procedure (LGIP) requires the proposed generation to be capable of delivering the requested MW to the Point of Interconnection (POI) **at a 0.95 lagging power factor**. For analysis of the power factor requirement, the Customer-supplied data regarding inverter capabilities, collector field configuration, impedances and line charging, and transformer impedances were used. **Power Factor was tested in both full discharging and full charging modes.**

The results of the analysis indicate that the proposed plant design, without capacitors, **DOES meet** the 0.95 lagging power factor requirement at the POI for the requested MW level. Table 8 below summarizes the approved MW at the POI, along with the MVAR capability at the POI required to meet the 0.95 lagging power factor requirement at the POI.

Table 8: MW Approved and MVAR Capability Required at the POI to Meet Power Factor Requirements

DEP Generator Interconnection Queue No.	MW Requested	MW Approved	MVAR Capability Required
479	100.0	**100.0**	32.9

The plant Mvar capability must be available at all MW injection levels above 10% of rated MW output. An automatic voltage regulator must be included in the power plant controller to automatically adjust inverter reactive power injection to smoothly and quickly maintain a voltage schedule to be provided by the utility.

If the plant design changes, the power factor analysis will need be repeated and the approved MW level may change.

3.4 Short Circuit Analysis Results

A short circuit assessment was performed to assess the impact of the proposed generation addition on transmission system equipment capabilities. The assessment indicates that no short circuit equipment capabilities will be exceeded as result from the proposed generation additions and associated transmission upgrades.

The results of the short circuit assessment are based on Customer provided generation equipment data and location. Also, the prudent use of engineering assumptions and typical values for some data were used. If the units' technical data or interconnection points to the transmission system changes, the results of this analysis may need to be reevaluated.

3.5 Harmonics Assessment

There is potential interaction of harmonic current injections from the Customer's proposed generation and certain capacitor banks on the DEP system. Testing may be necessary after the actual in-service date of this generation and the Customer will be responsible for mitigation of any detrimental impacts to the system.

3.6 Interconnection of Customer's Generation

The point of interconnection for Queue #479 is in a new 230kV bay in the Wake 500kV Substation. The one-line is provided as Figure 1.

The customer should verify that the MVA ratings of their connecting lines are sufficient to accommodate delivering the total MVA output to the point of interconnection at the required 0.95 power factor.

3.7 Estimate of Interconnection Cost

The costs below are typical values.

Generator Tie Line

Description:	DEP will construct a short generator tie line from Wake 500kV Substation to the DEP property line.
Estimated Cost:	$885,045
Contingency (20%):	$177,009

Taxes

Description:	NC utility tax of 7%
Estimated Cost:	$74,344

Interconnection Facilities Cost Estimate:	**$1,136,398**

Network Upgrades at the POI

230kV Bay

Description:	Build new 230kV bay at Wake 500kV Substation with 2 breakers.
Estimated Cost:	$3,946,275
Contingency (20%):	$789,255

Taxes

Description:	NC utility tax of 7%
Estimated Cost:	$331,487

Network Upgrades at the POI Cost Estimate:	**$5,067,017**

4 SUMMARY

This Generator Interconnection Facilities Study assessed the impact of interconnecting a new battery storage facility with a requested summer/winter rating of 100.0 MW. Power flow analysis showed no issues when this storage plant is discharging. However, when charging, this storage facility requires two transmission upgrades to receive NRIS for charging.

This request can be approved for NRIS in both charging and discharging modes **after completion of the upgrades listed in Table 5**. Alternatively, this request can be approved for NRIS in discharging mode and ERIS in charging mode without any network upgrades other than at the interconnection.

Interconnection upgrades to the DEP Transmission System are necessary to accommodate Q479.

DEP will require at least 32 months to construct the interconnection after a firm written agreement to proceed is obtained from the customer. If NRIS charging is required, the schedule would extend to at least 48 months to include the network upgrades listed in Table 5.

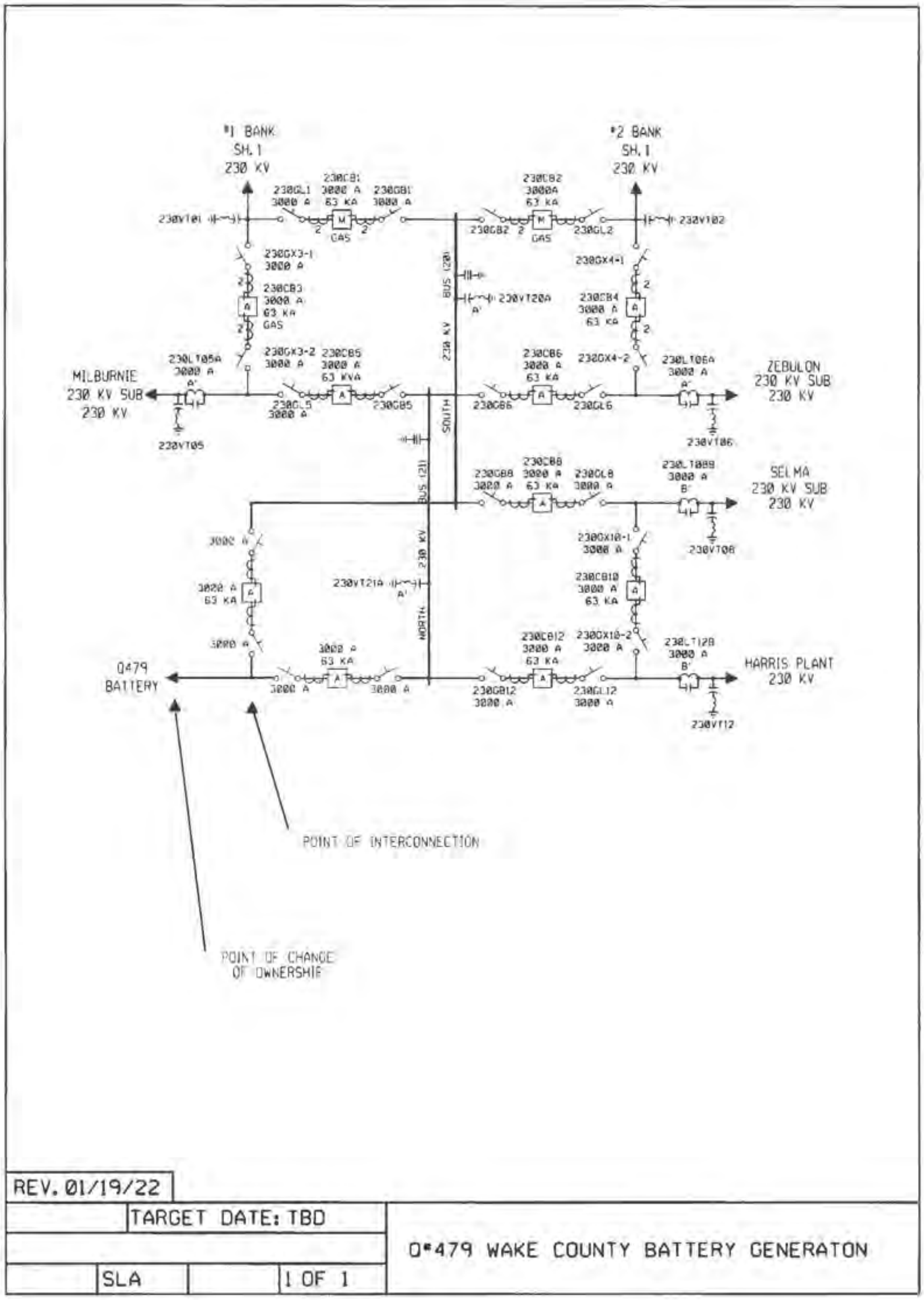
Power-flow	$0
Stability	$0
Short Circuit	$0
Network Upgrades at the POI	$5,067,017
Interconnection Facilities	$1,136,398
Total Estimate	$6,203,415
Optional for NRIS Charging	
Power flow (20% contingency added)	$104,500,000

Study Completed by: William Quaintance
Bill Quaintance, PE, Duke Energy Progress

Reviewed by: Mark Byrd
Mark Byrd, PE, Duke Energy Progress

APPENDIX I : FIGURES

- Figure 1 –



CIGFUR II & III Reliability Panel Direct Cross Examination Exhibit 1

I/A

Attachment C
E-100, Sub 179
CIGFUR

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

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Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes as well as highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

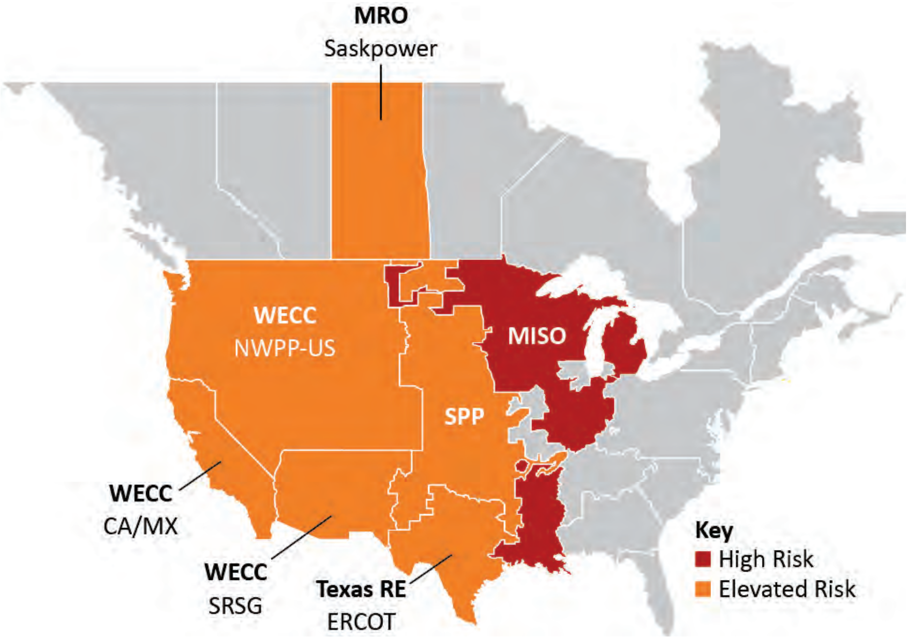

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.

- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.

- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see **Figure 2**). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

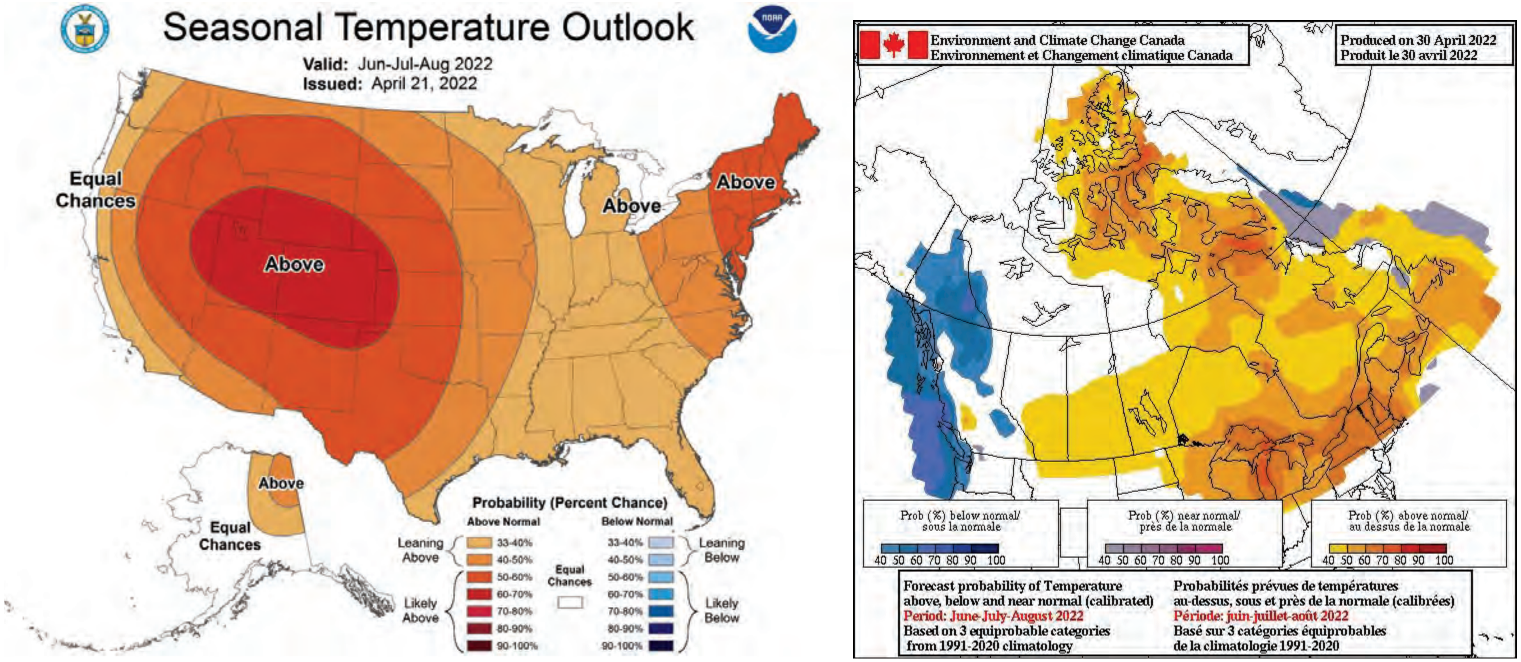

Figure 2: United States and Canada Summer Temperature Outlook[2]

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[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

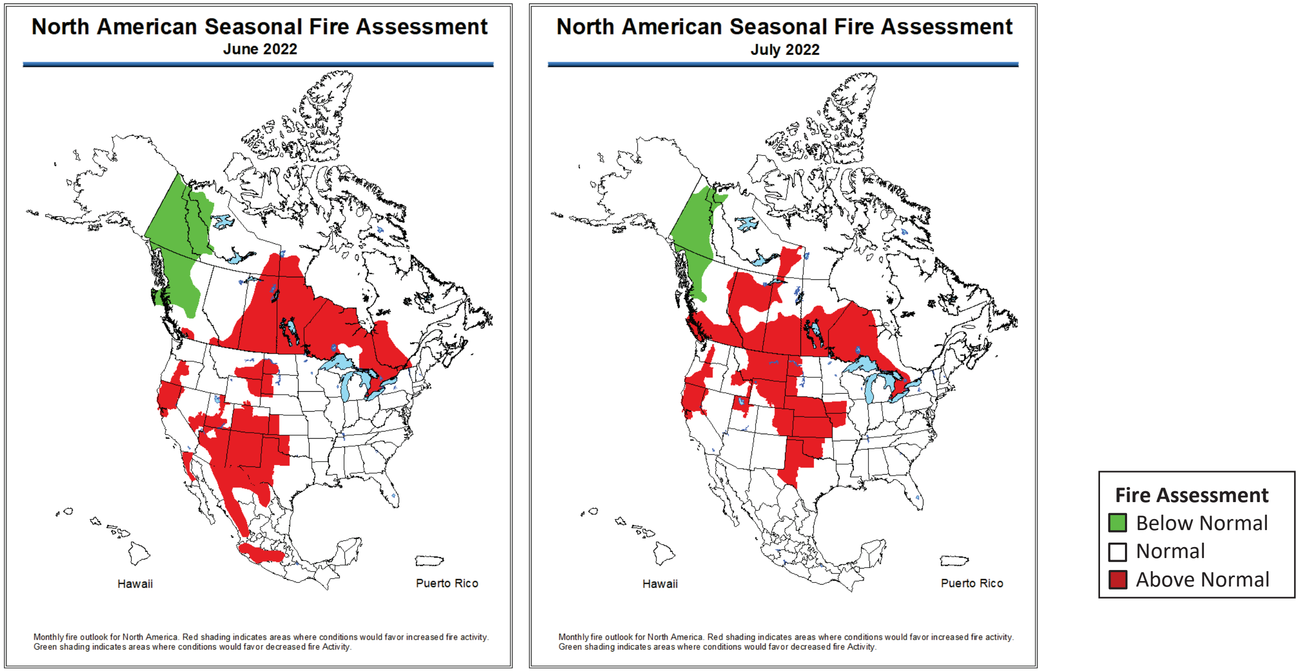

Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

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[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

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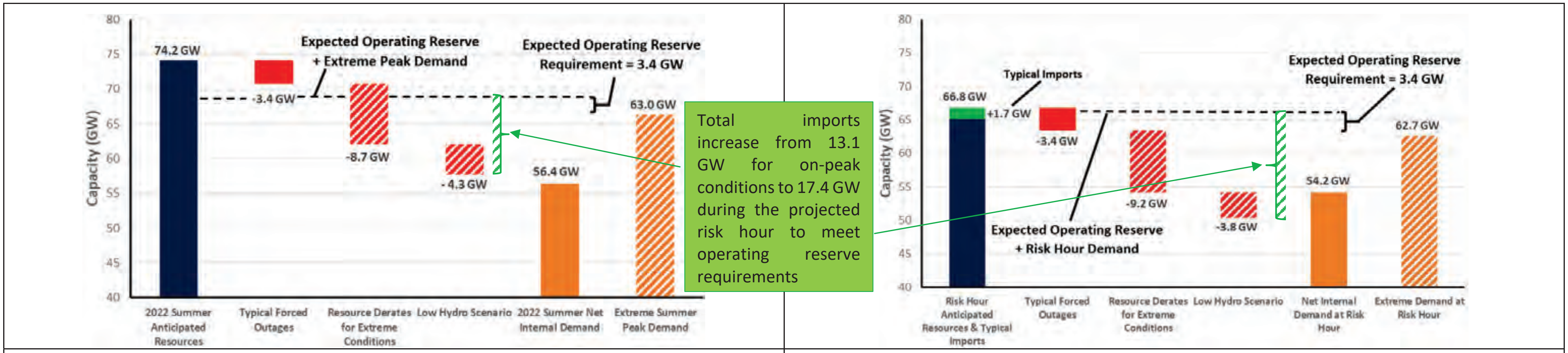
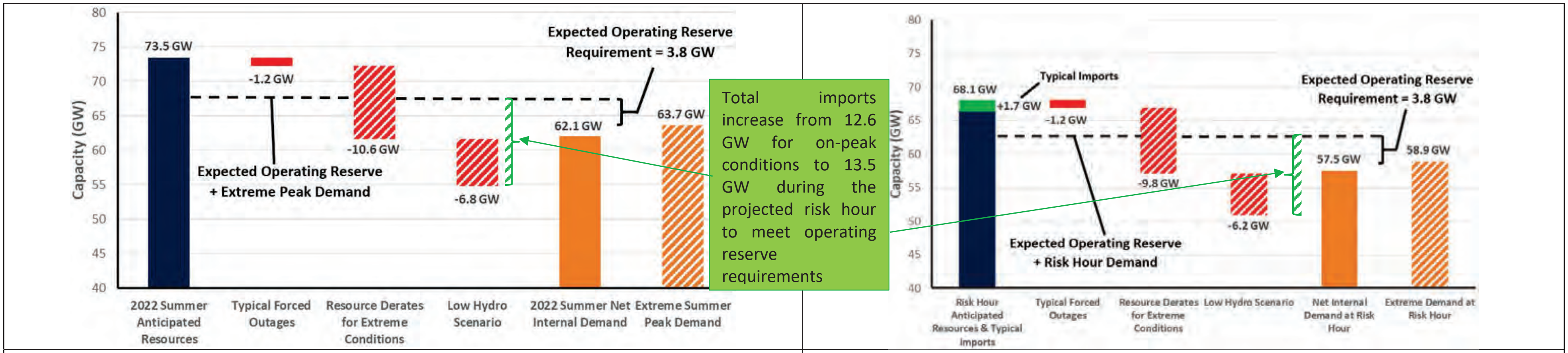
[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation



Total imports increase from 13.1 GW for on-peak conditions to 17.4 GW during the projected risk hour to meet operating reserve requirements

WECC-CA/MX On-Peak

WECC-CA/MX Risk Hour (8:00 p.m. local)

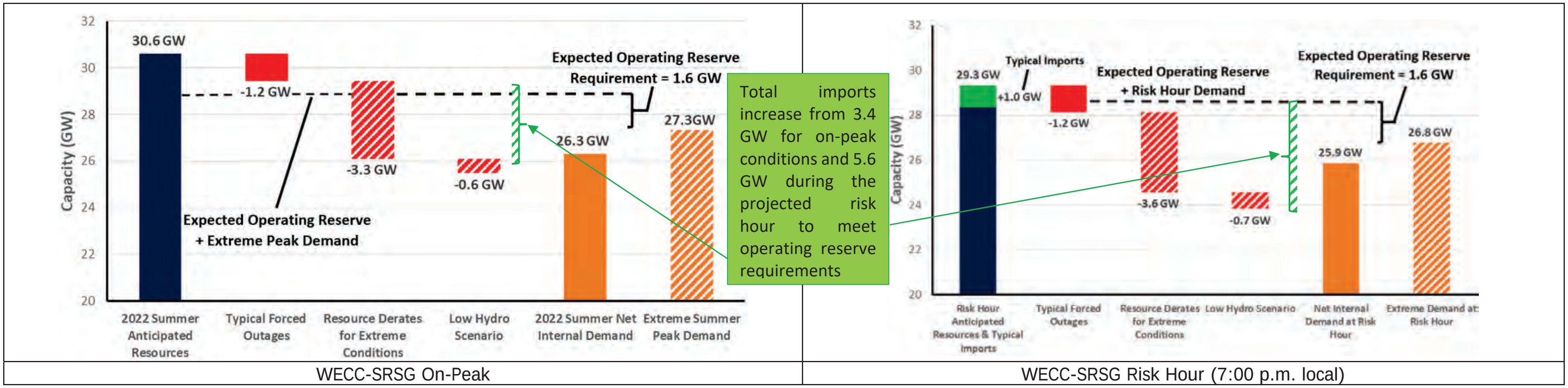


Total imports increase from 12.6 GW for on-peak conditions to 13.5 GW during the projected risk hour to meet operating reserve requirements

WECC-NWPP-US On-Peak

WECC-NWPP-US Risk Hour (7:00 p.m. local)

Figure 4: Risk Scenarios for WECC U.S. Assessment Areas



Total imports increase from 3.4 GW for on-peak conditions and 5.6 GW during the projected risk hour to meet operating reserve requirements

WECC-SRSG On-Peak	WECC-SRSG Risk Hour (7:00 p.m. local)

Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

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[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

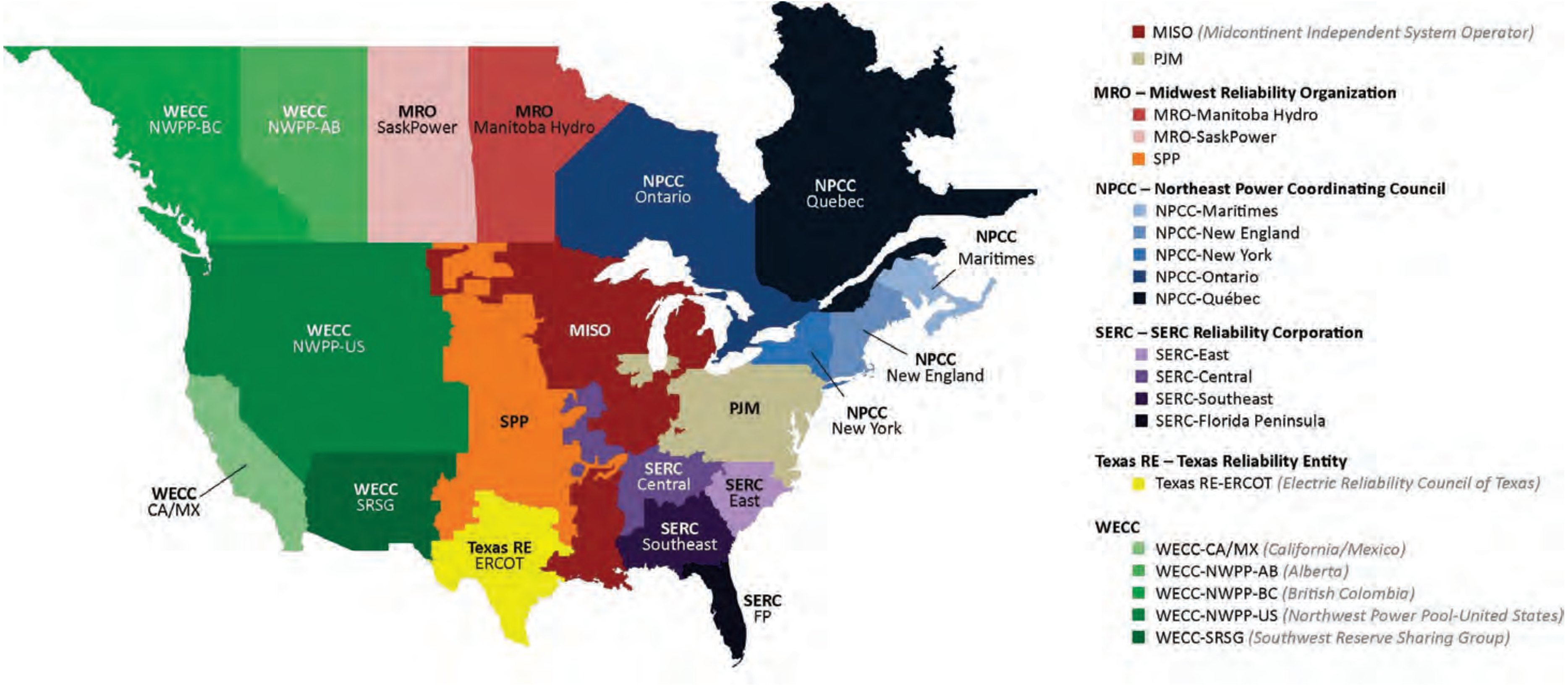
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like these are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



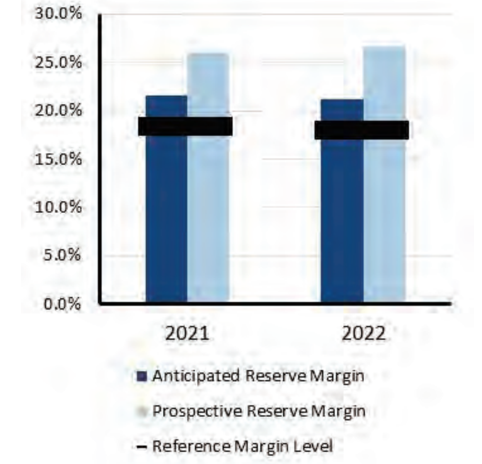
Highlights

- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

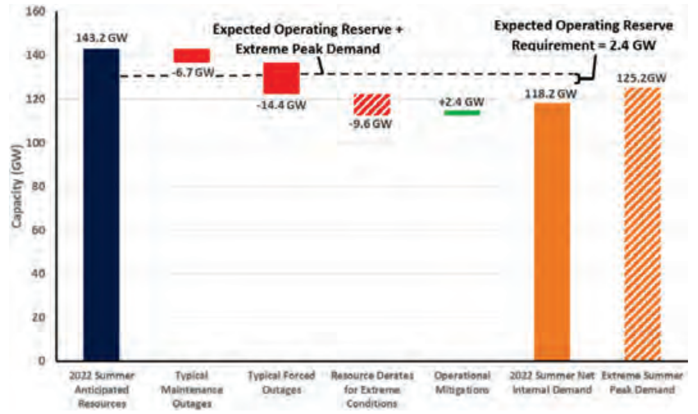
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

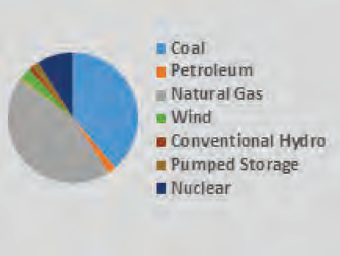
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum of last five years of outages

Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions

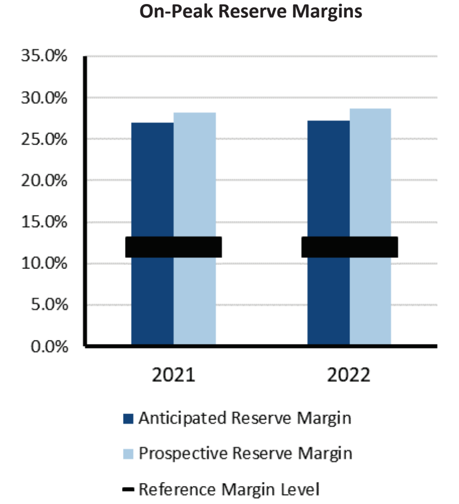


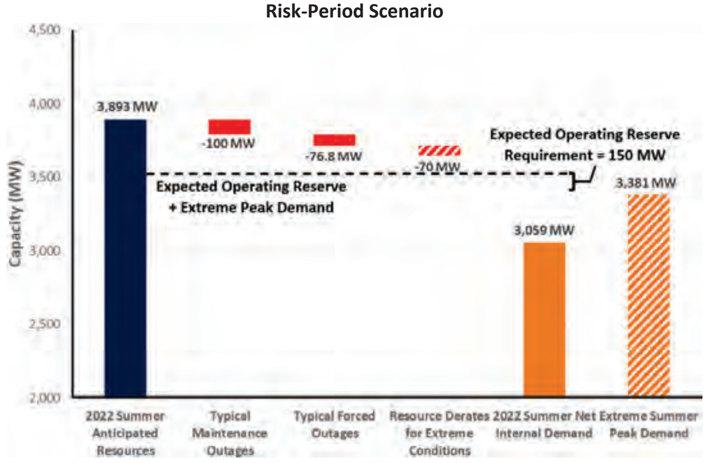
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





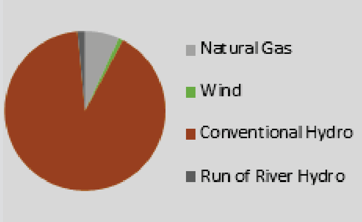
Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates



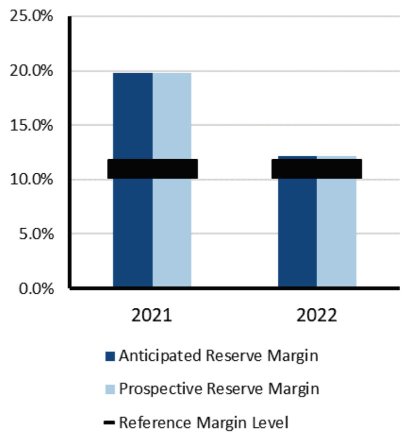
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

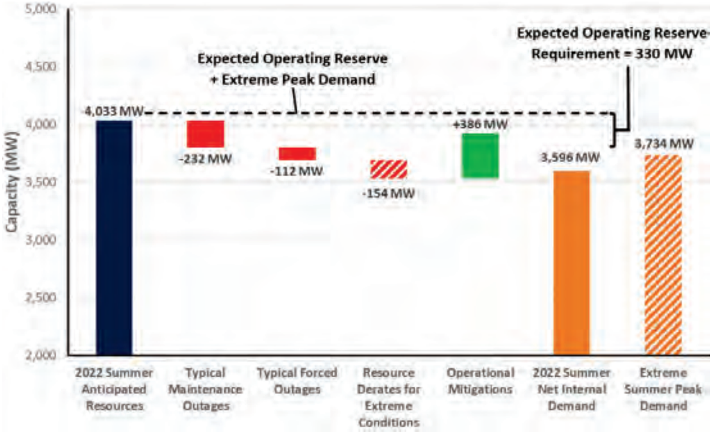
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

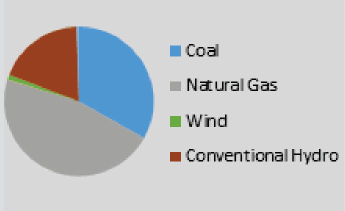
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

Forced Outages: Estimated by using SaskPower forced outage model

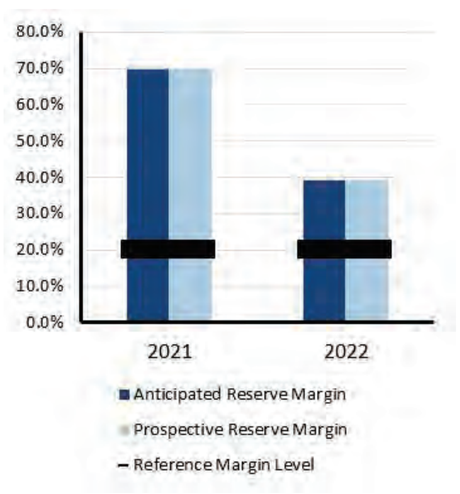
Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer



Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

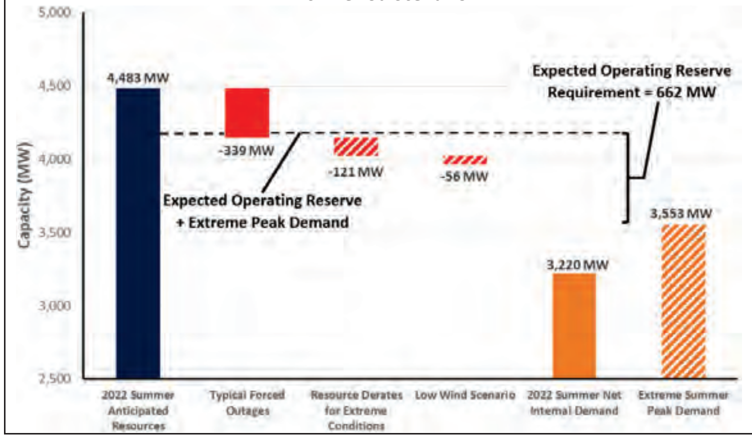
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

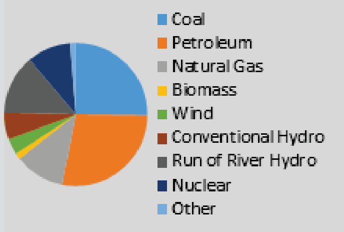
Risk Period: Highest risk for unserved energy at peak demand hour

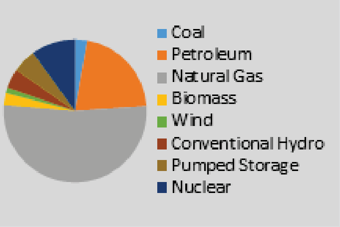
Demand Scenarios: Net internal demand (50/50) and (99/1) extreme demand forecast

Outages: Based on historical operating experience

Extreme Derates: Based on historical data for ambient temperature thermal de-rates

Low Wind Scenario: A low-likelihood scenario resulting in no wind resources





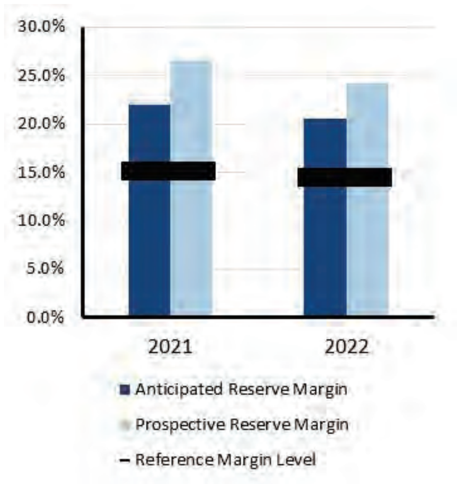
Highlights

- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.

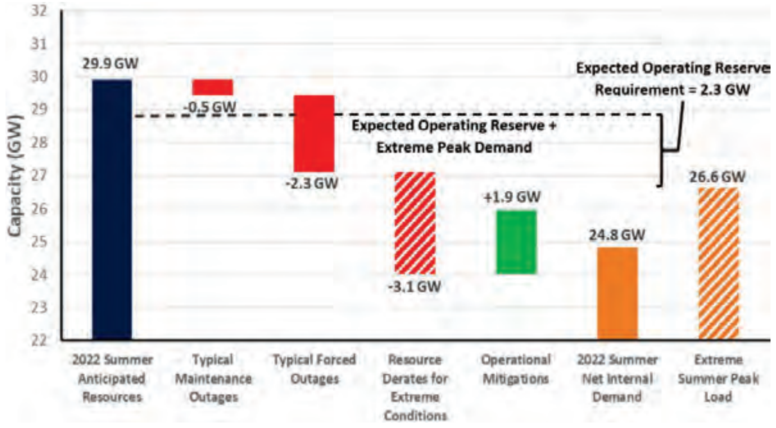
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

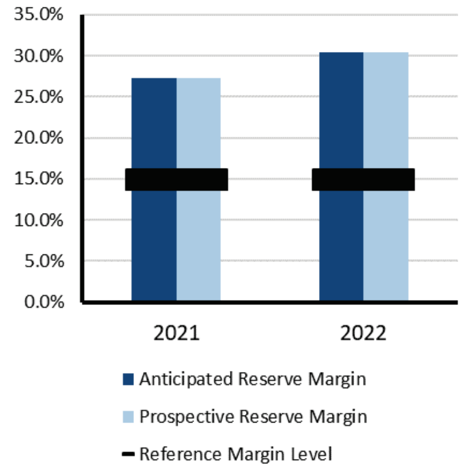
Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.

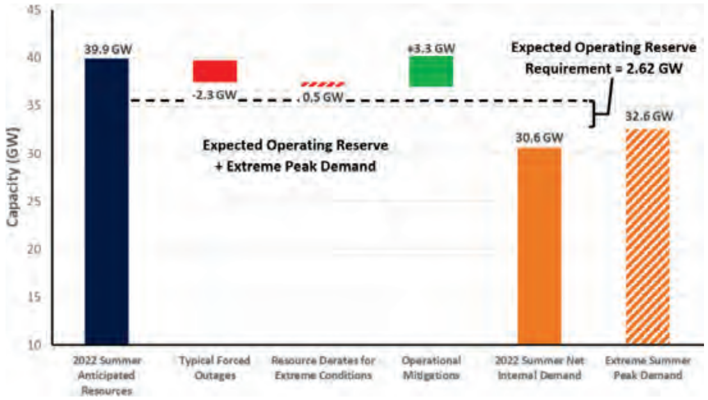
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



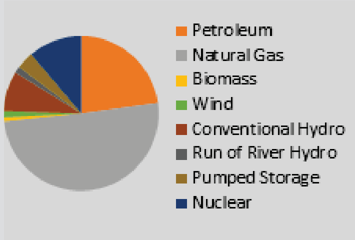
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Forced Outages: Based on historical 5-year averages

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*



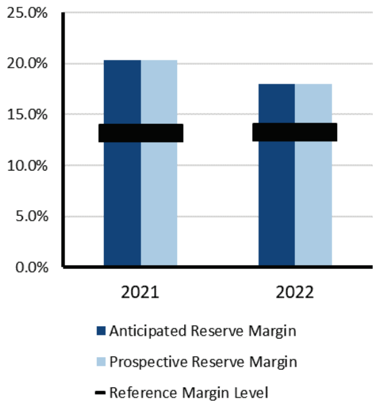
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

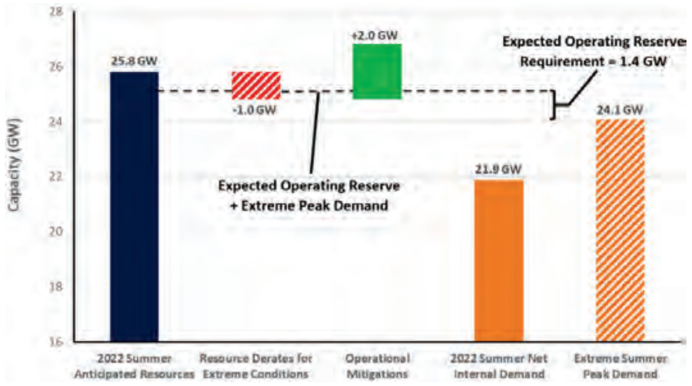
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



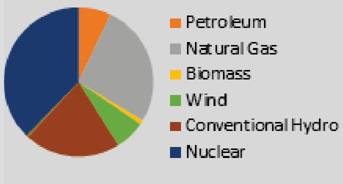
Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



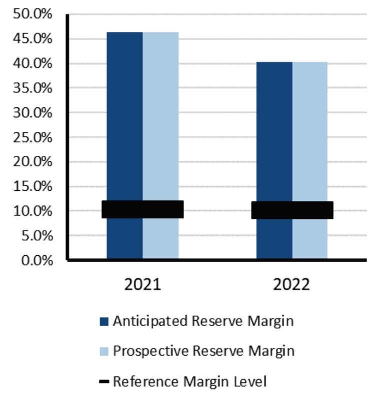
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

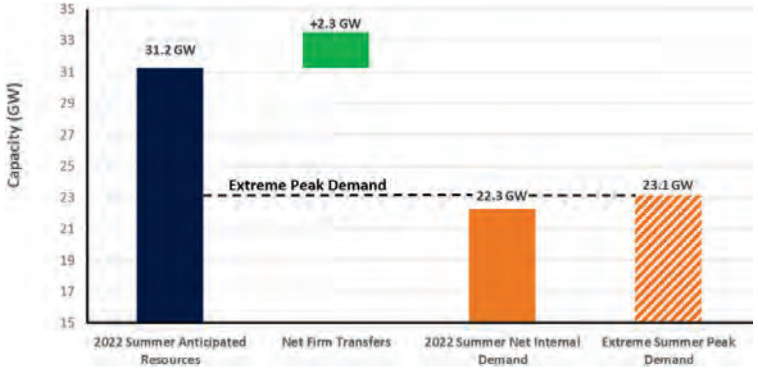
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario

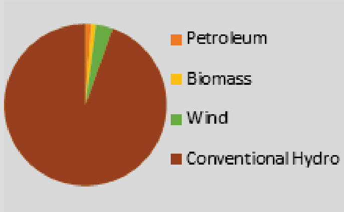


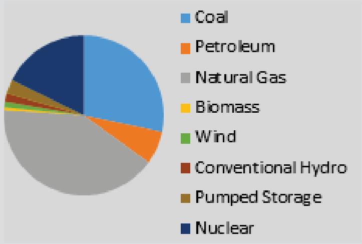
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Imports anticipated from neighbors during emergencies

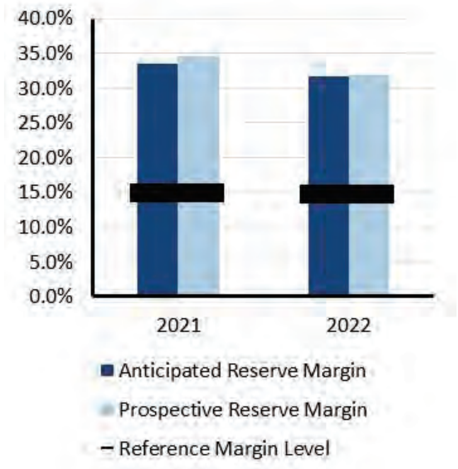




Highlights

- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

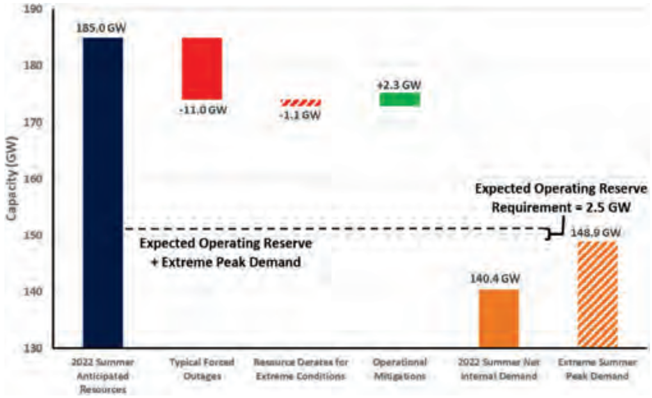
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.3 GW based on operational/emergency procedures

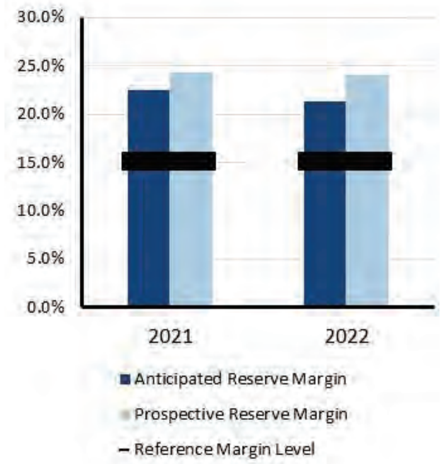
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

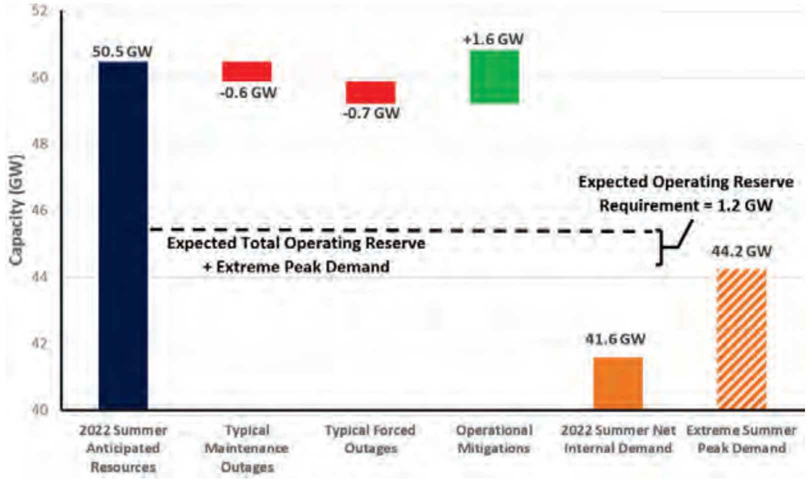
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

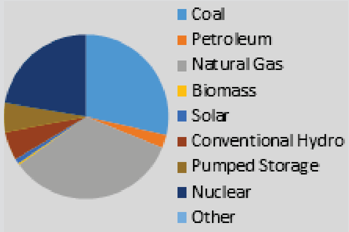
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures

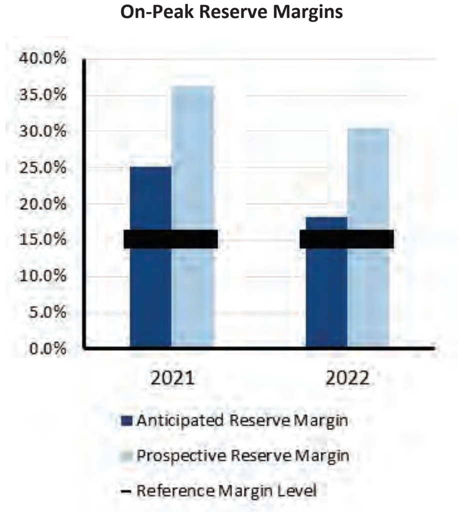


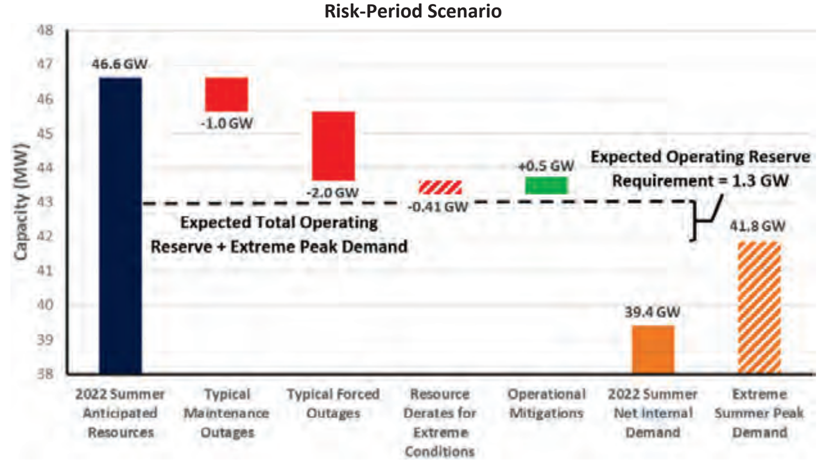
Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.


On-Peak Reserve Margins


Risk-Period Scenario

Scenario Description (See Data Concepts and Assumptions)

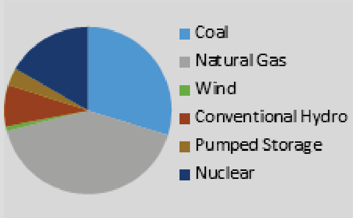
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

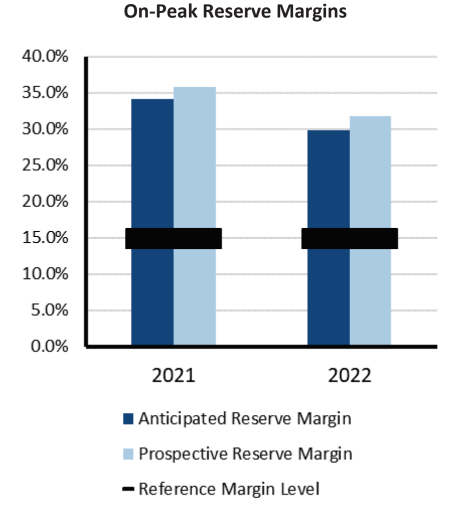


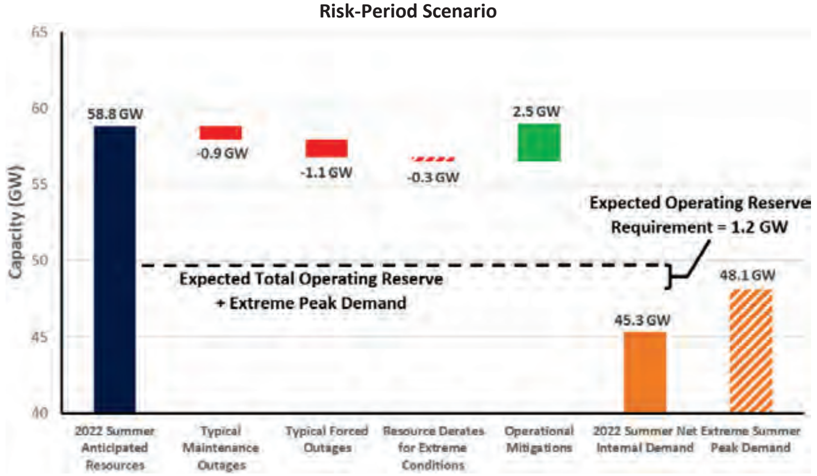
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.


On-Peak Reserve Margins


Risk-Period Scenario

Scenario Description (See Data Concepts and Assumptions)

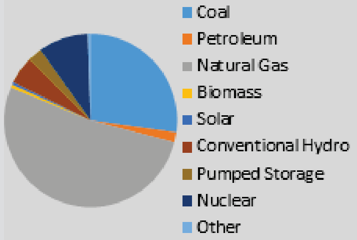
Risk Period: Highest risk for unserved energy at peak demand hour

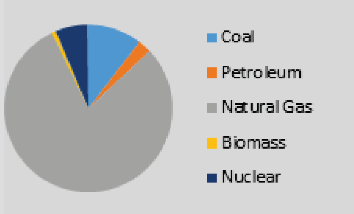
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures





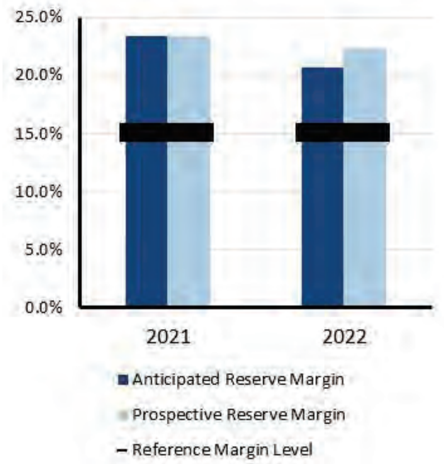
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

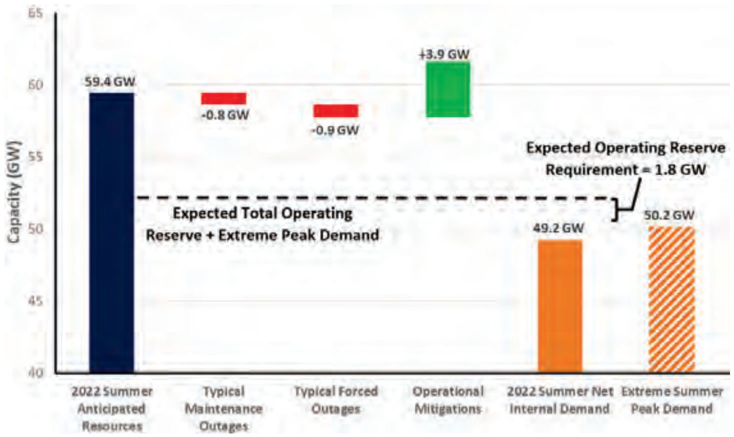
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

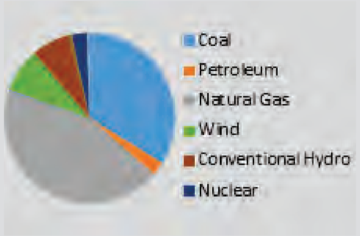
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures



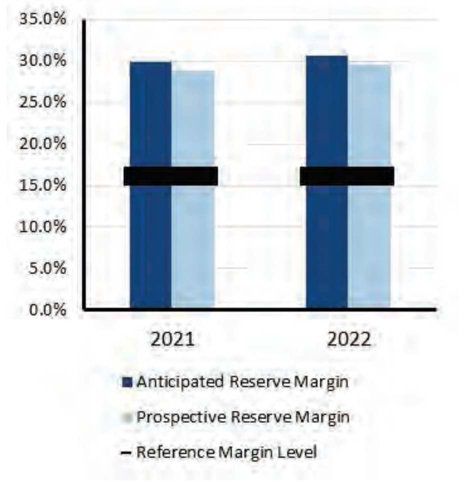
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

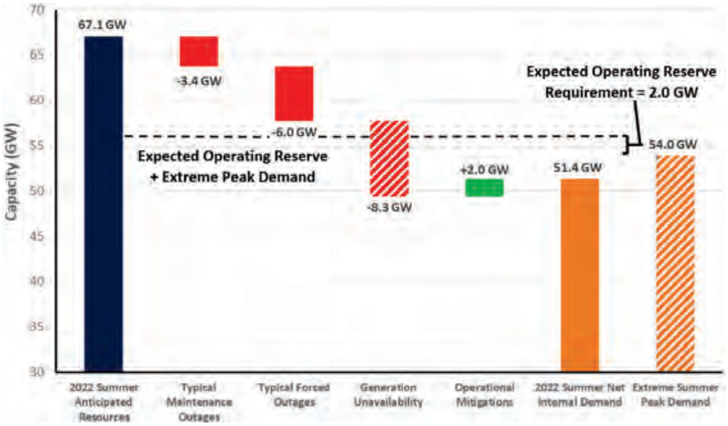
Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

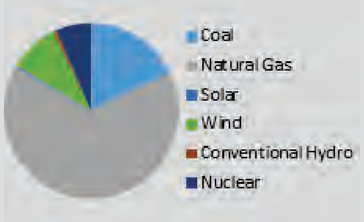
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert



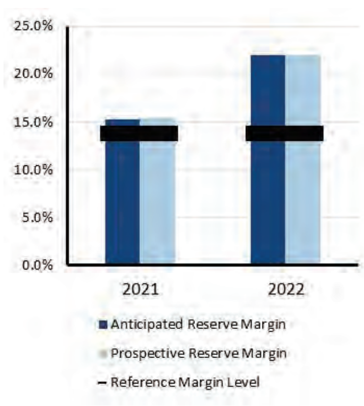
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario

Scenario Description (See Data Concepts and Assumptions)

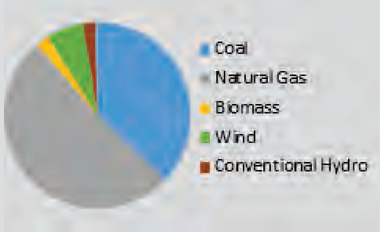
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



Highlights

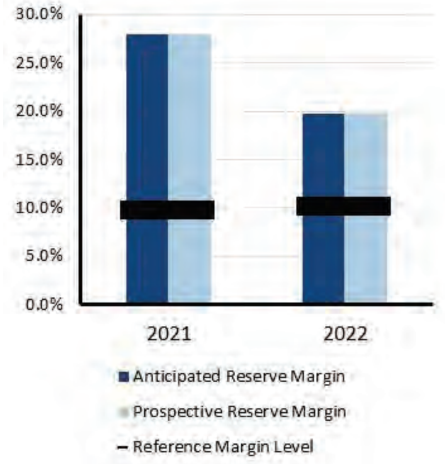
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

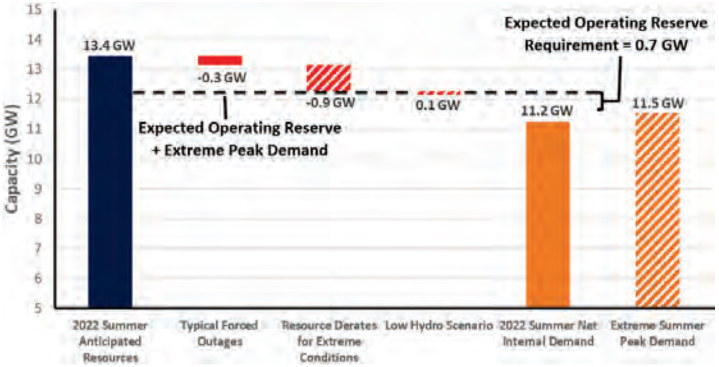
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

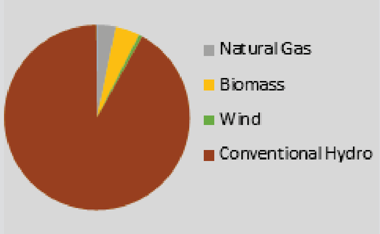
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



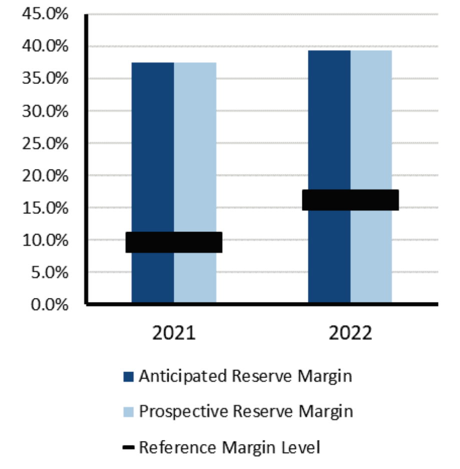
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

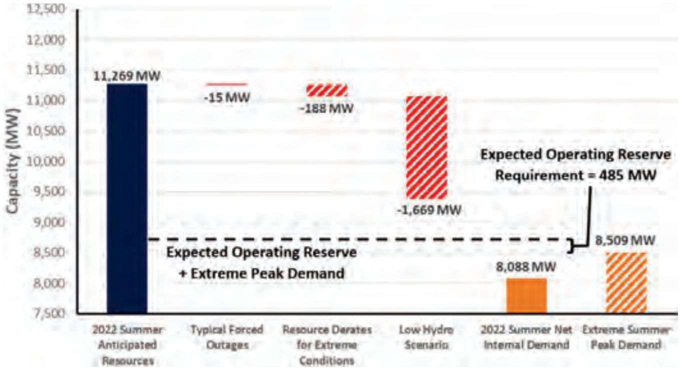
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

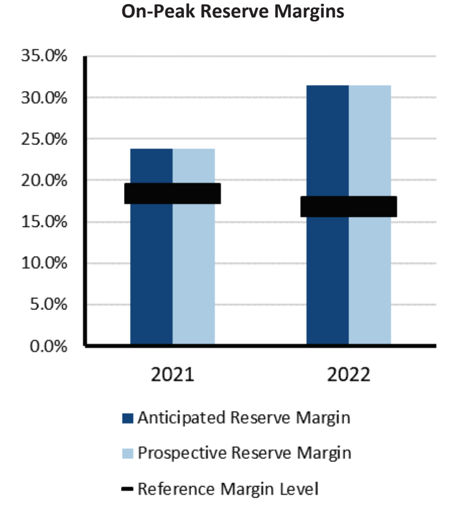
Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

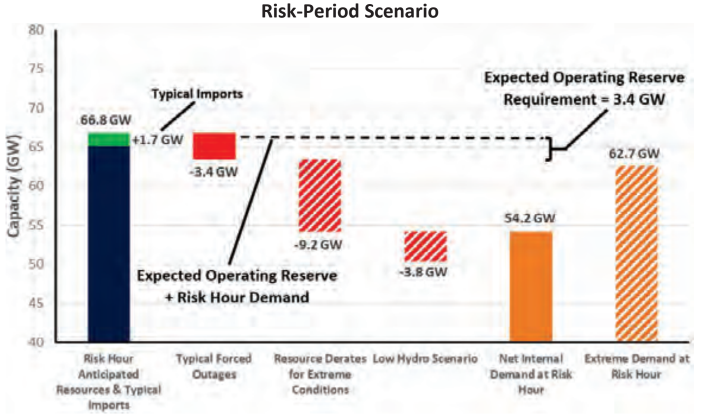
Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See [Data Concepts and Assumptions](#))

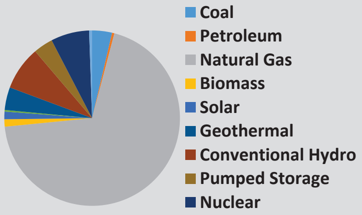
Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



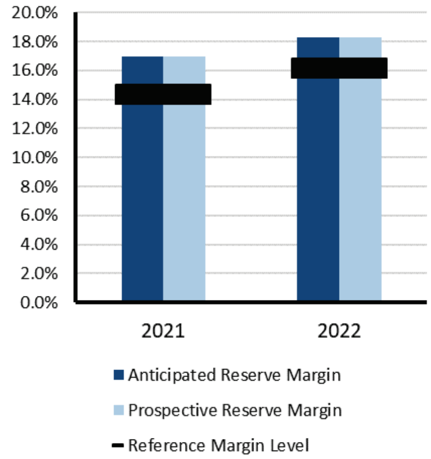
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

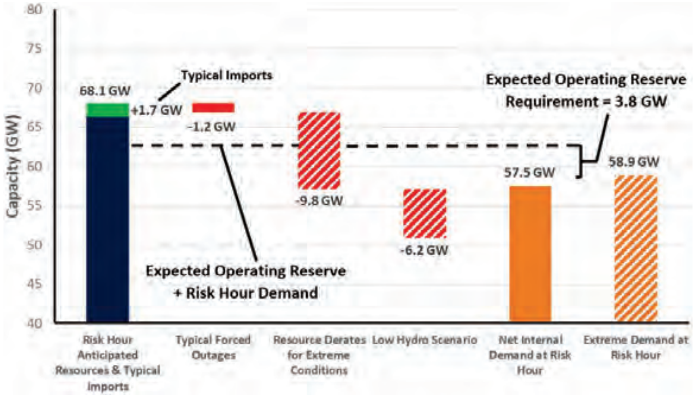
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

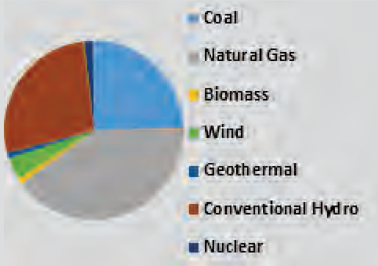
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



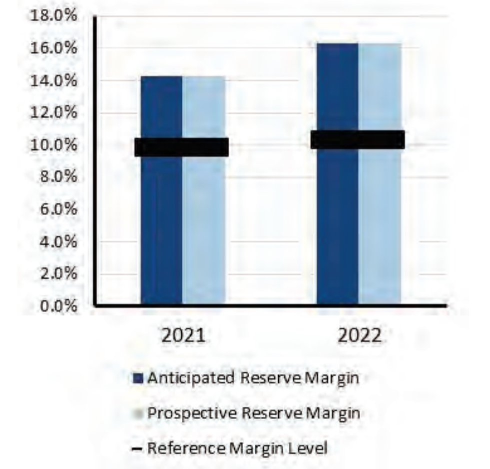
Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

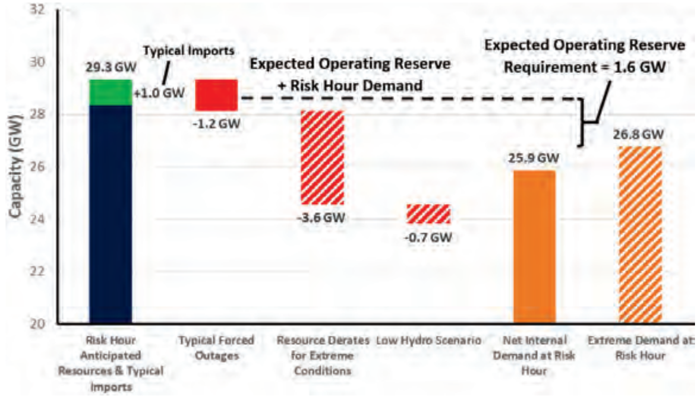
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

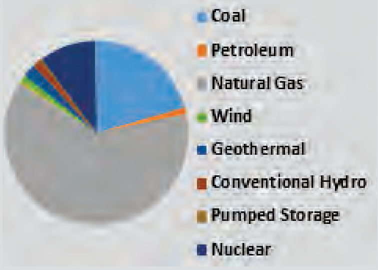
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
    - Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
    - Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2021 Long-Term Reliability Assessment* data has been used for most of this 2022 summer assessment period augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[7] or total internal demand for the summer and winter of each year.[8]
- Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

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[7] *Glossary of Terms* used in NERC Reliability Standards

[8] The summer season represents June–September and the winter season represents December–February.

[9] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[10] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[11] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022 summer as shown in **Figure 9**.

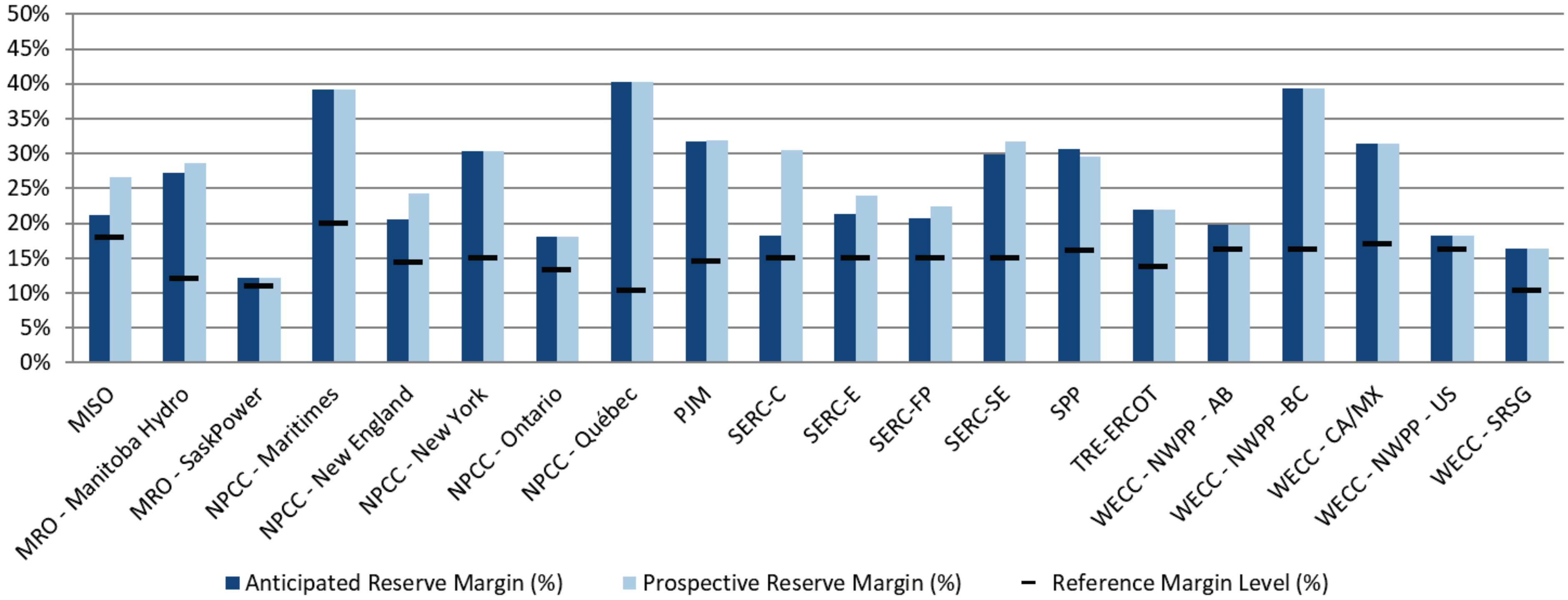

Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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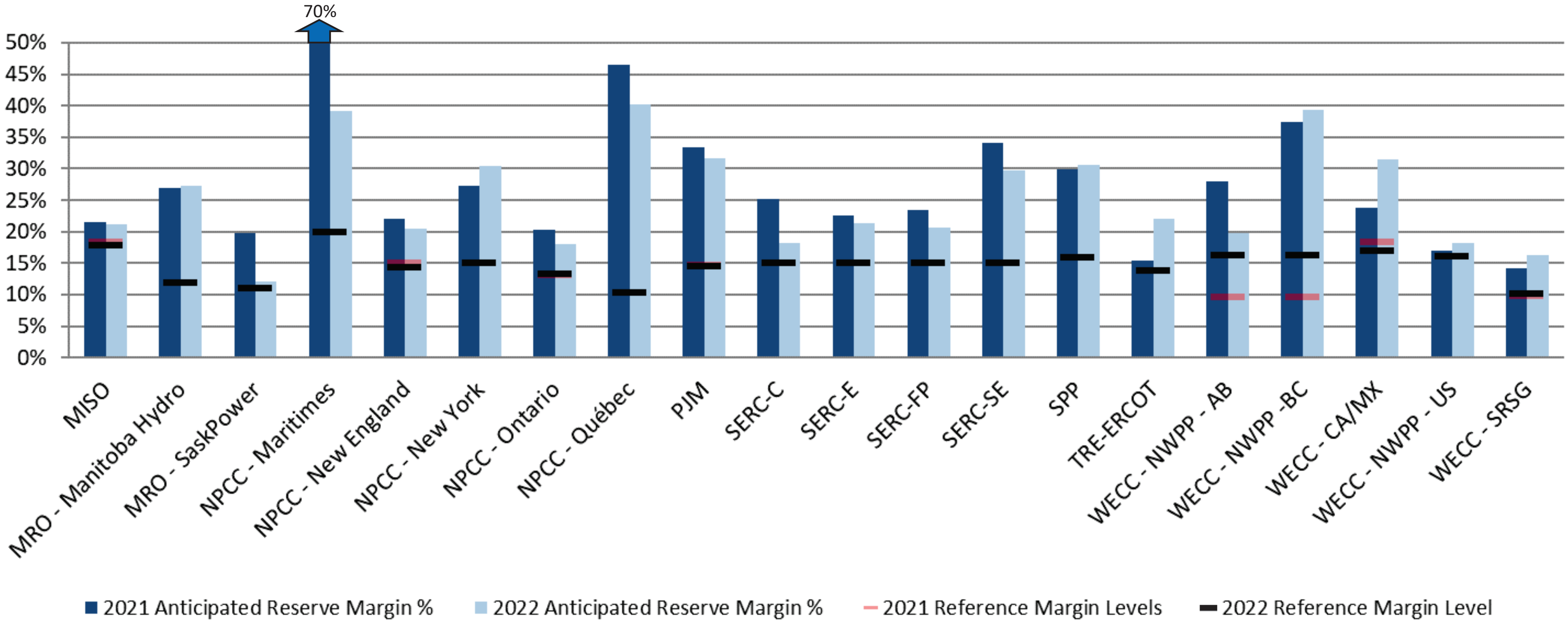
[11] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 11**.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

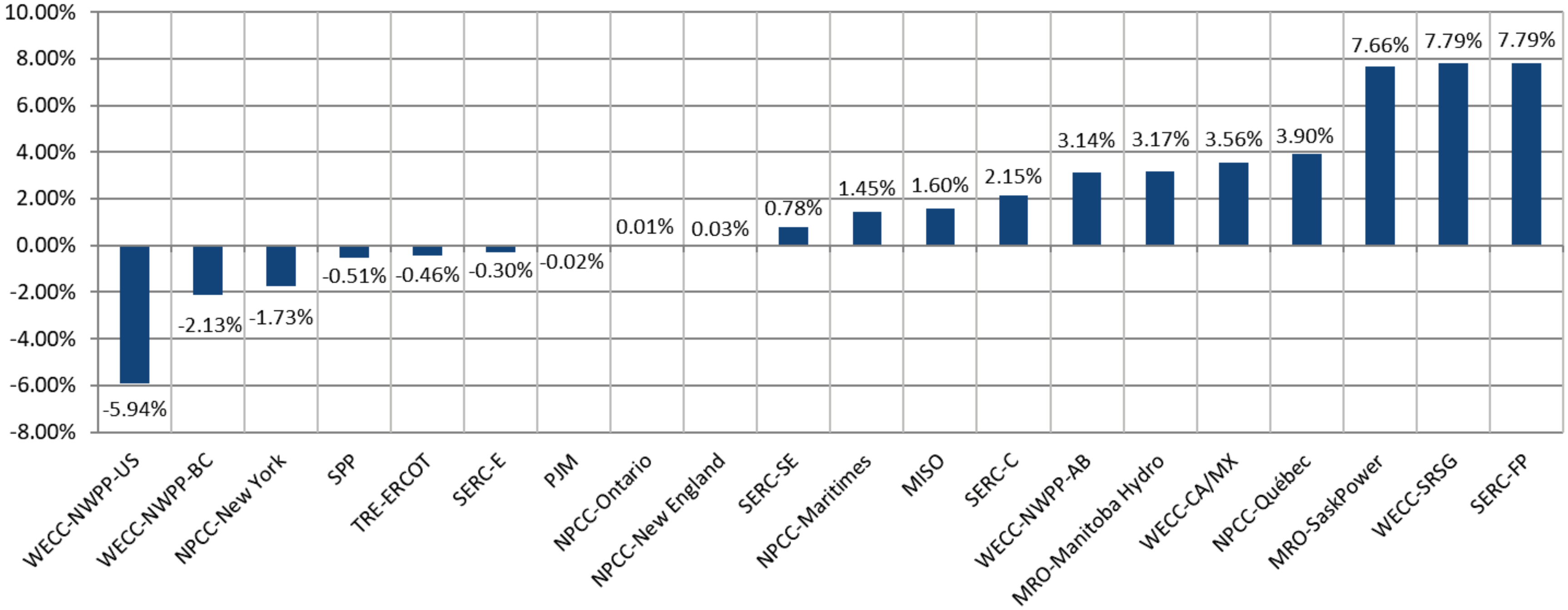


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

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[12] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data

Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data

Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data

Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

I/A

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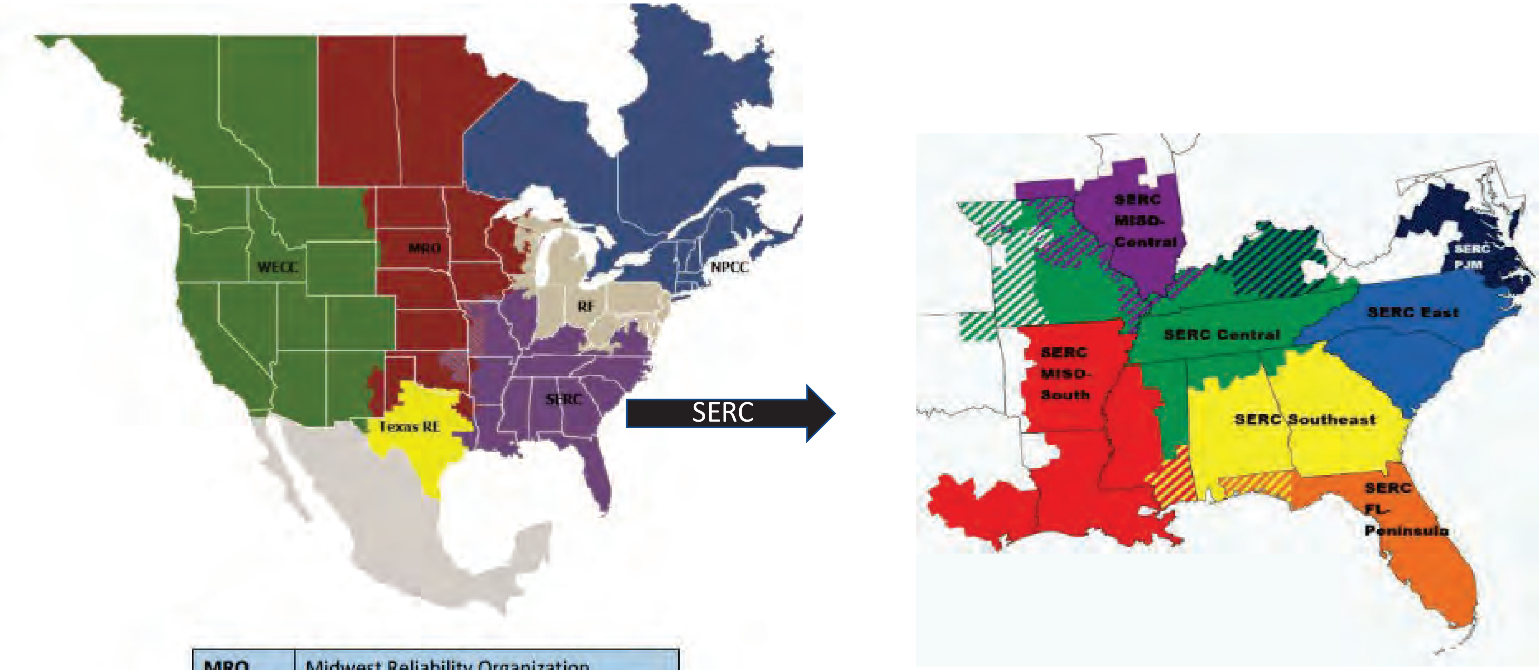
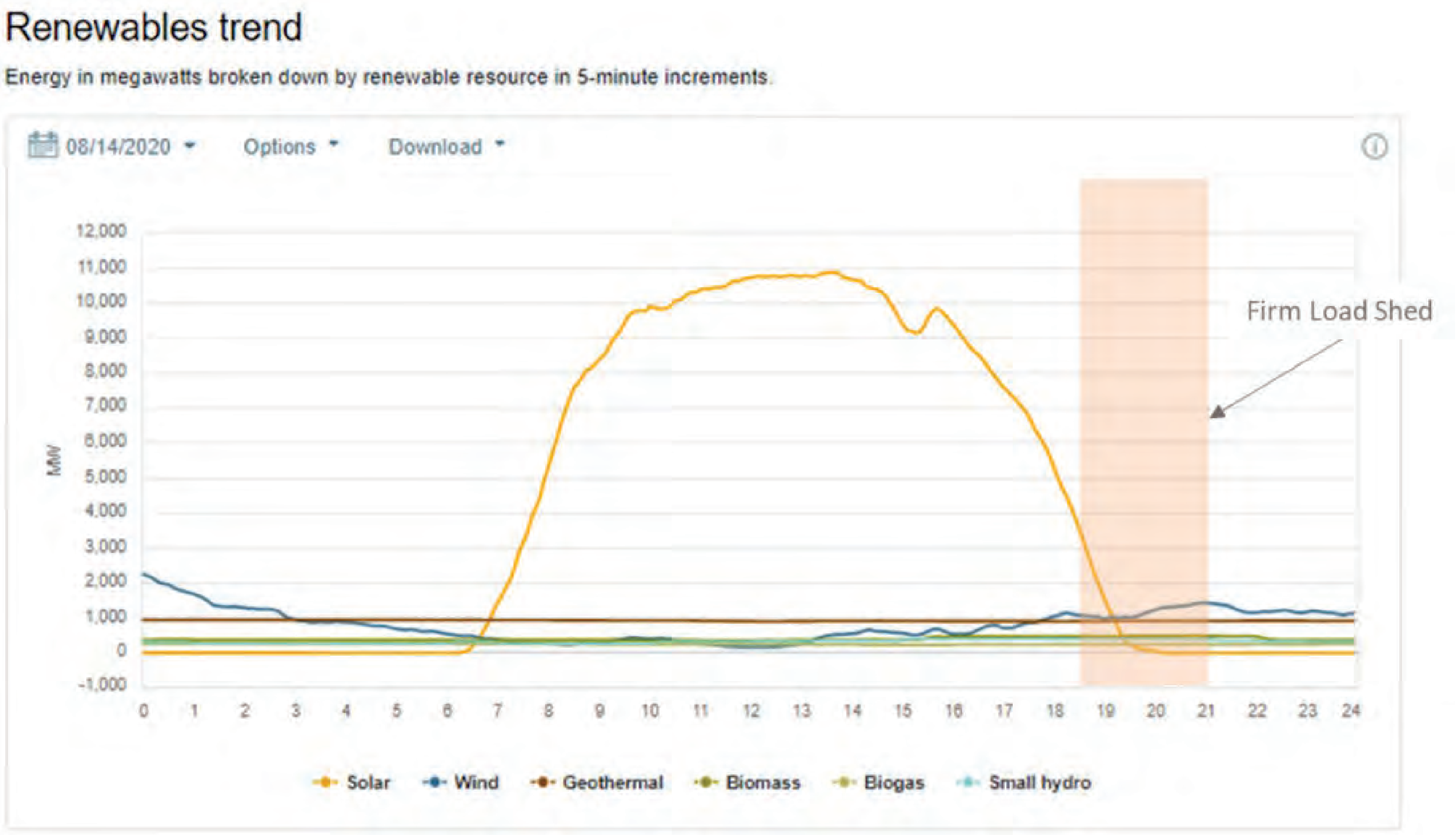
Figure 1: NERC Regional Entities, SERC Subregions



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Sources: www.NERC.com, www.SERC1.org

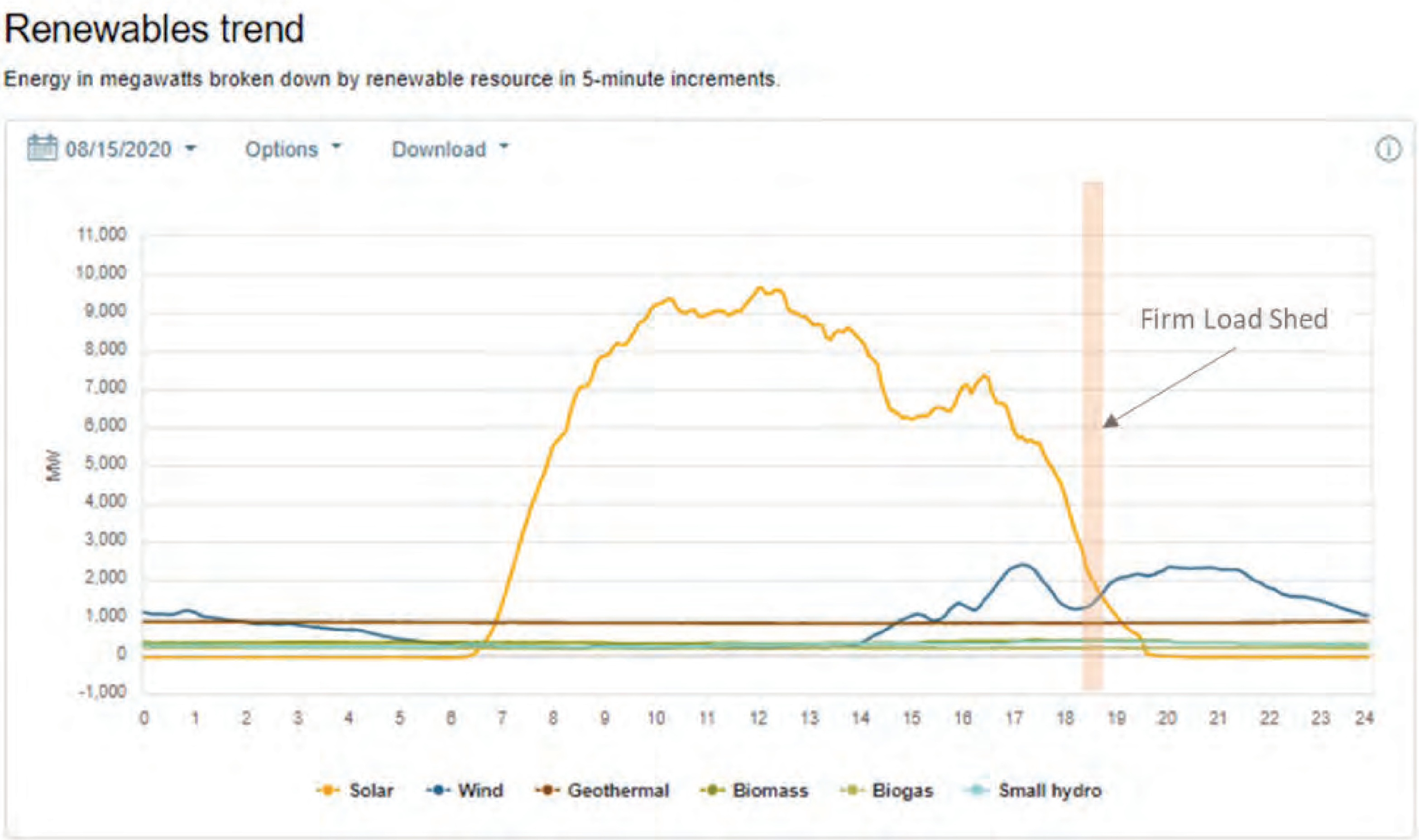
Figure 5: August 14-15, 2020 CAISO Firm Load Shed Events



Renewables trend

Energy in megawatts broken down by renewable resource in 5-minute increments.

Figure 5: August 14-15, 2020 CAISO Firm Load Shed Events (Continued)



Renewables trend

Energy in megawatts broken down by renewable resource in 5-minute increments.

Figure 7: Low Net Demand and High Net Demand Ramp Rate

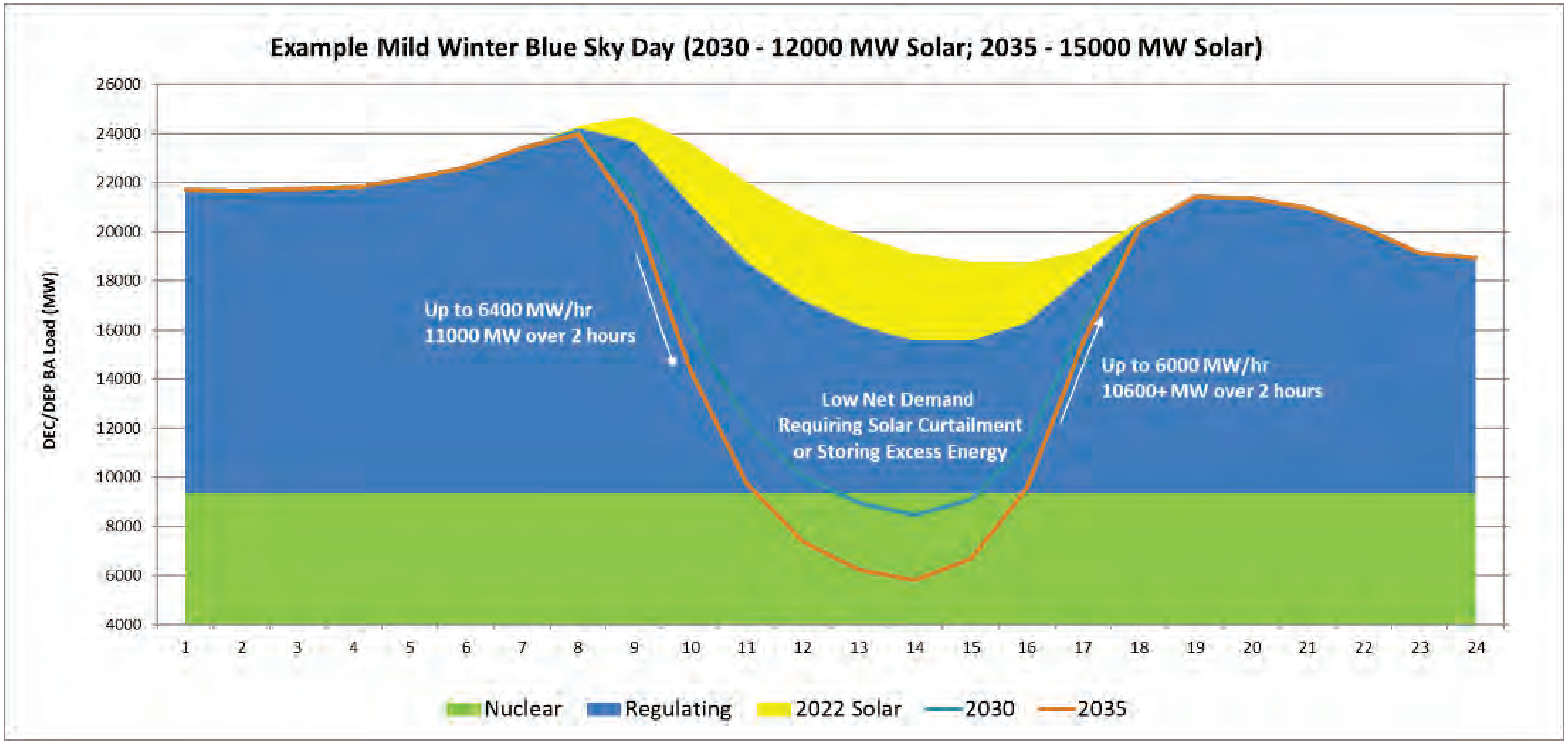


Figure 8 – Hot Summer Load Shape with 2030, 2035 Solar

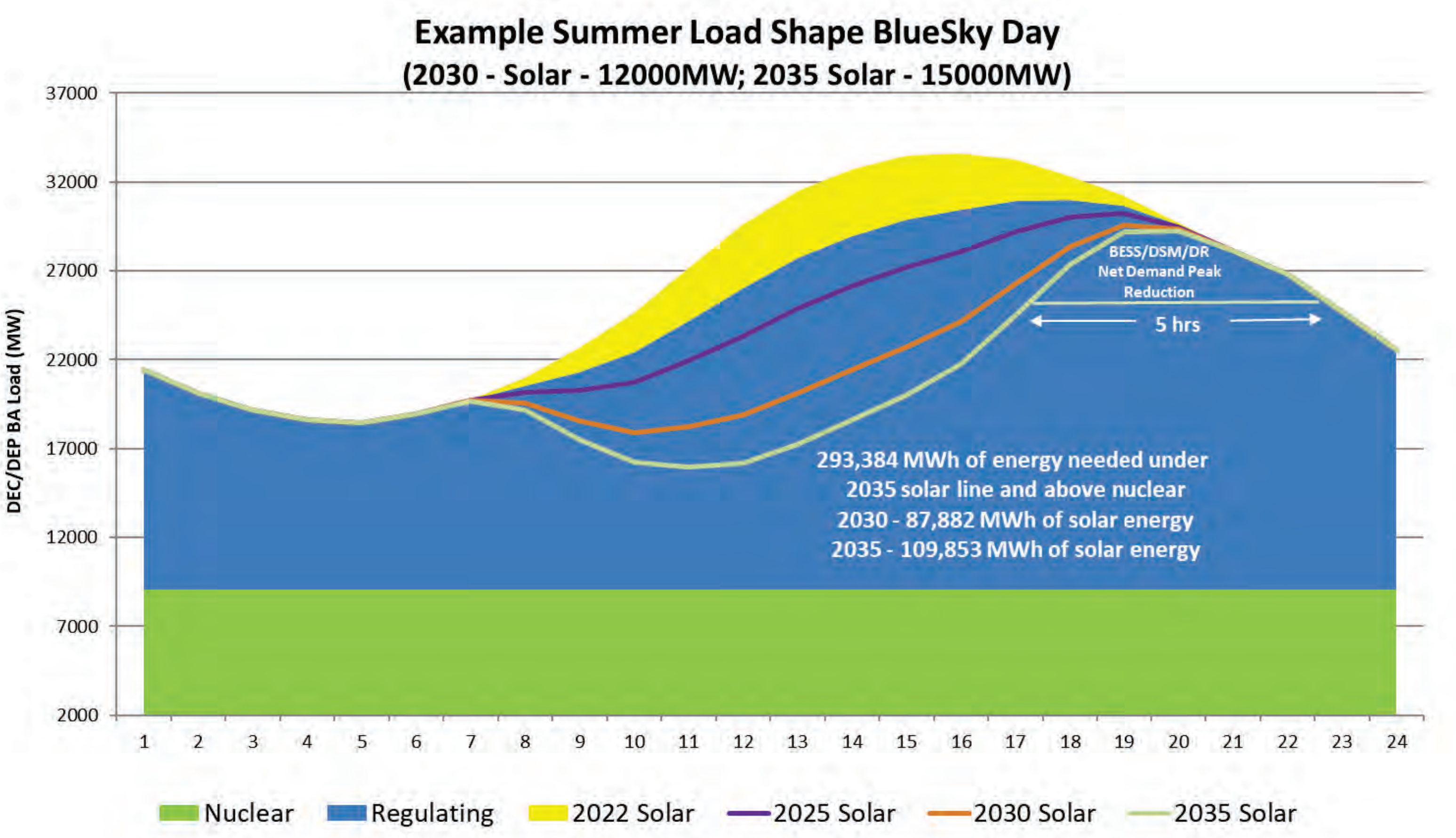


Figure 10: January 3-5, 2018 Solar Production vs Customer Demand

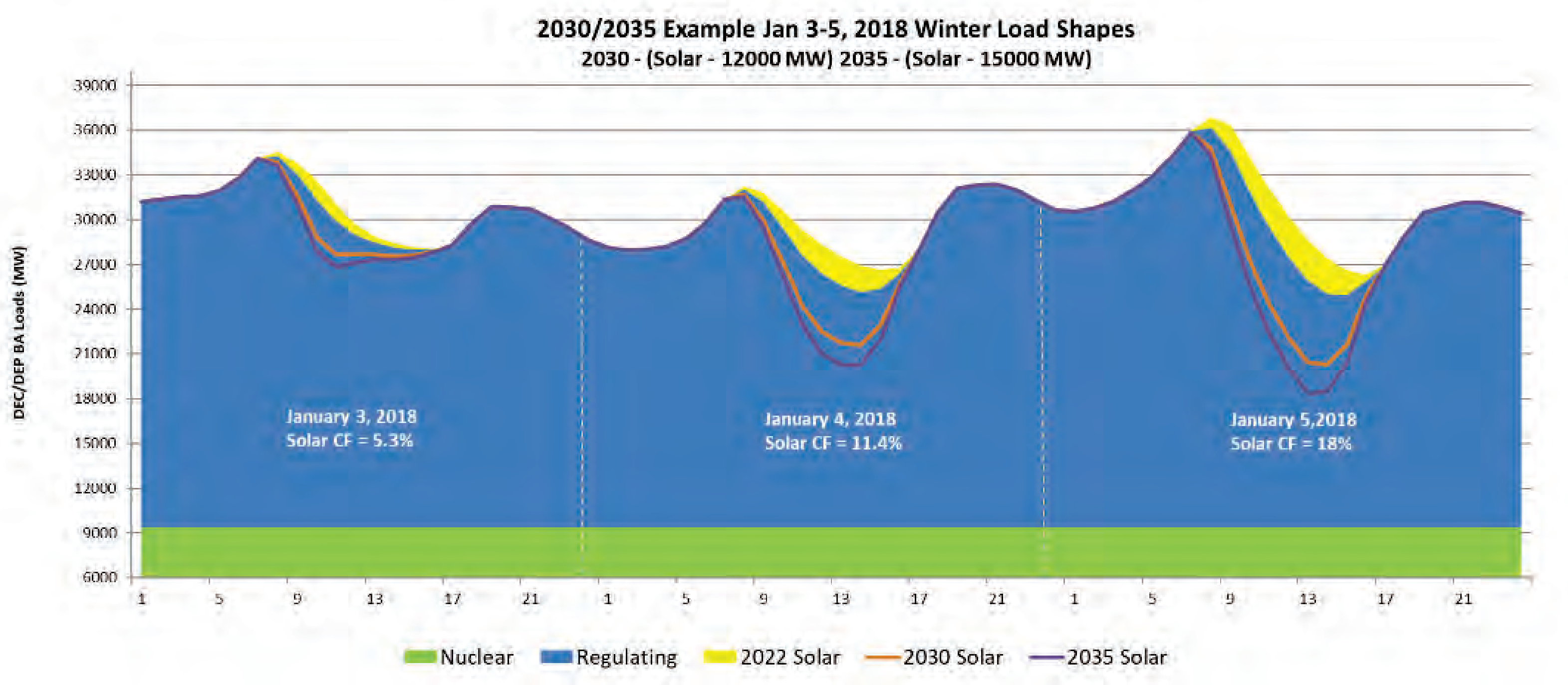
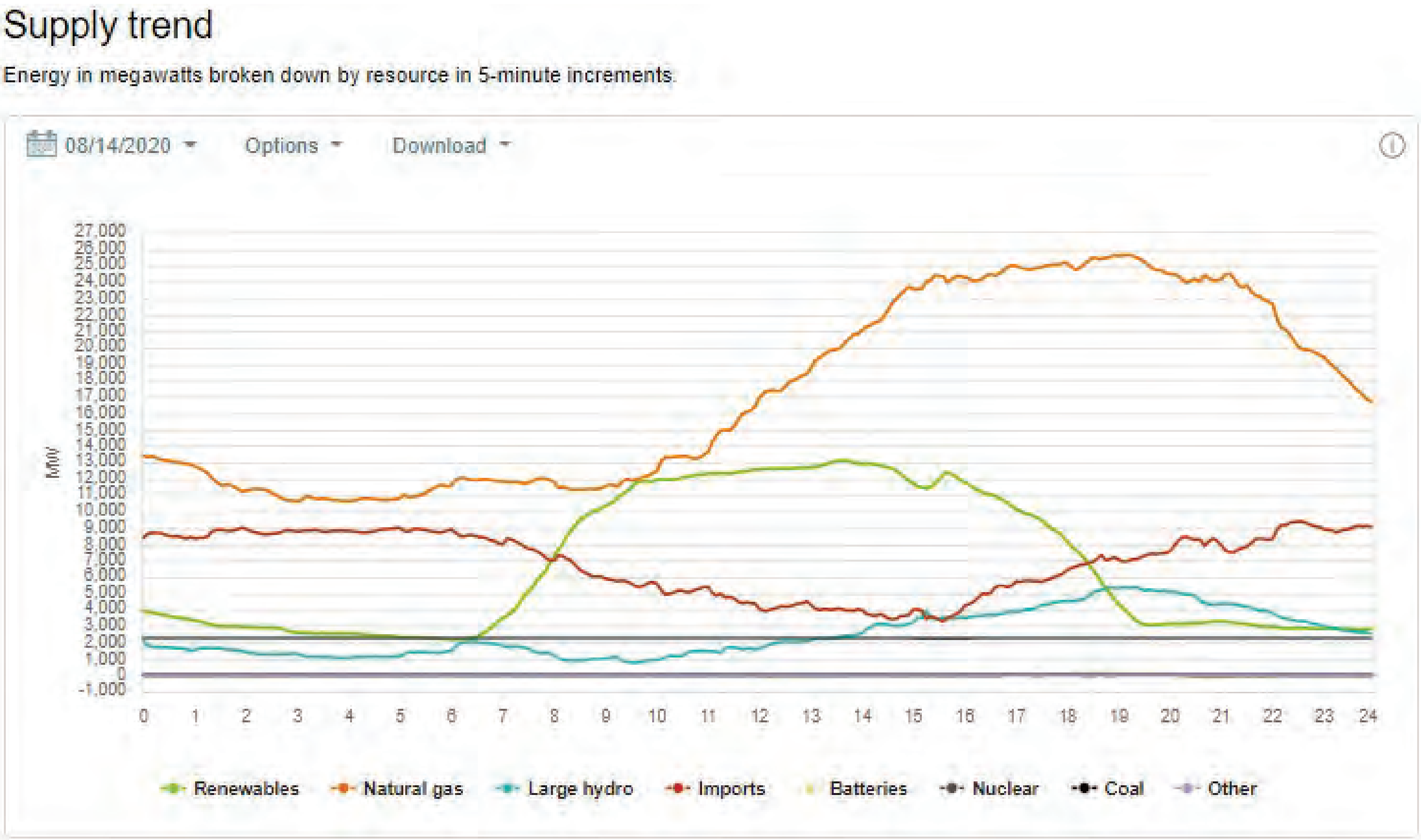


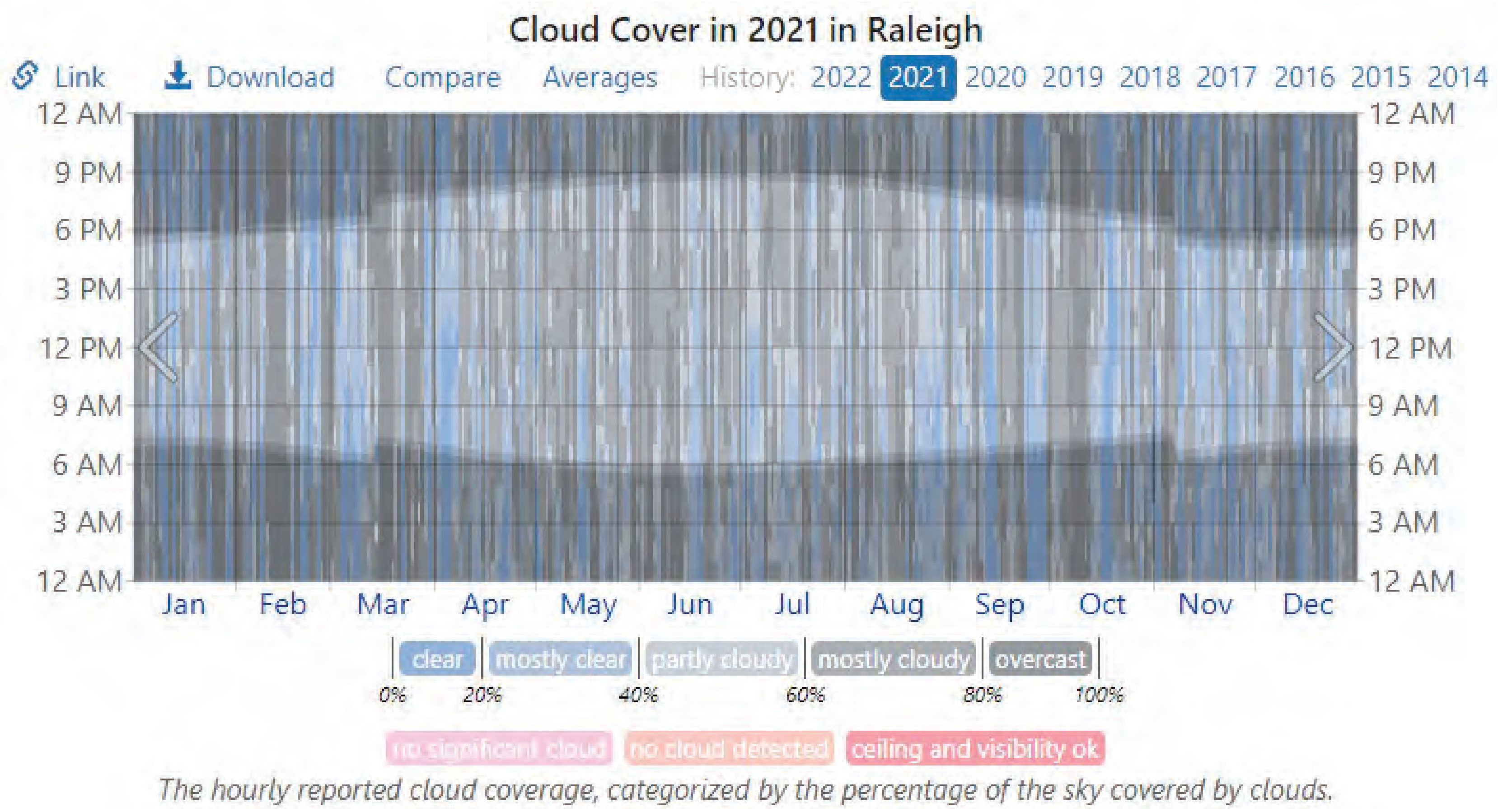
Figure 12: CAISO Power Supply Resources on August 14, 2020



Supply trend

Energy in megawatts broken down by resource in 5-minute increments.

Figure 13: 2021 Cloud Cover for Raleigh, NC and Barstow, CA



The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

Figure 13: 2021 Cloud Cover for Raleigh, NC and Barstow, CA (Continued)

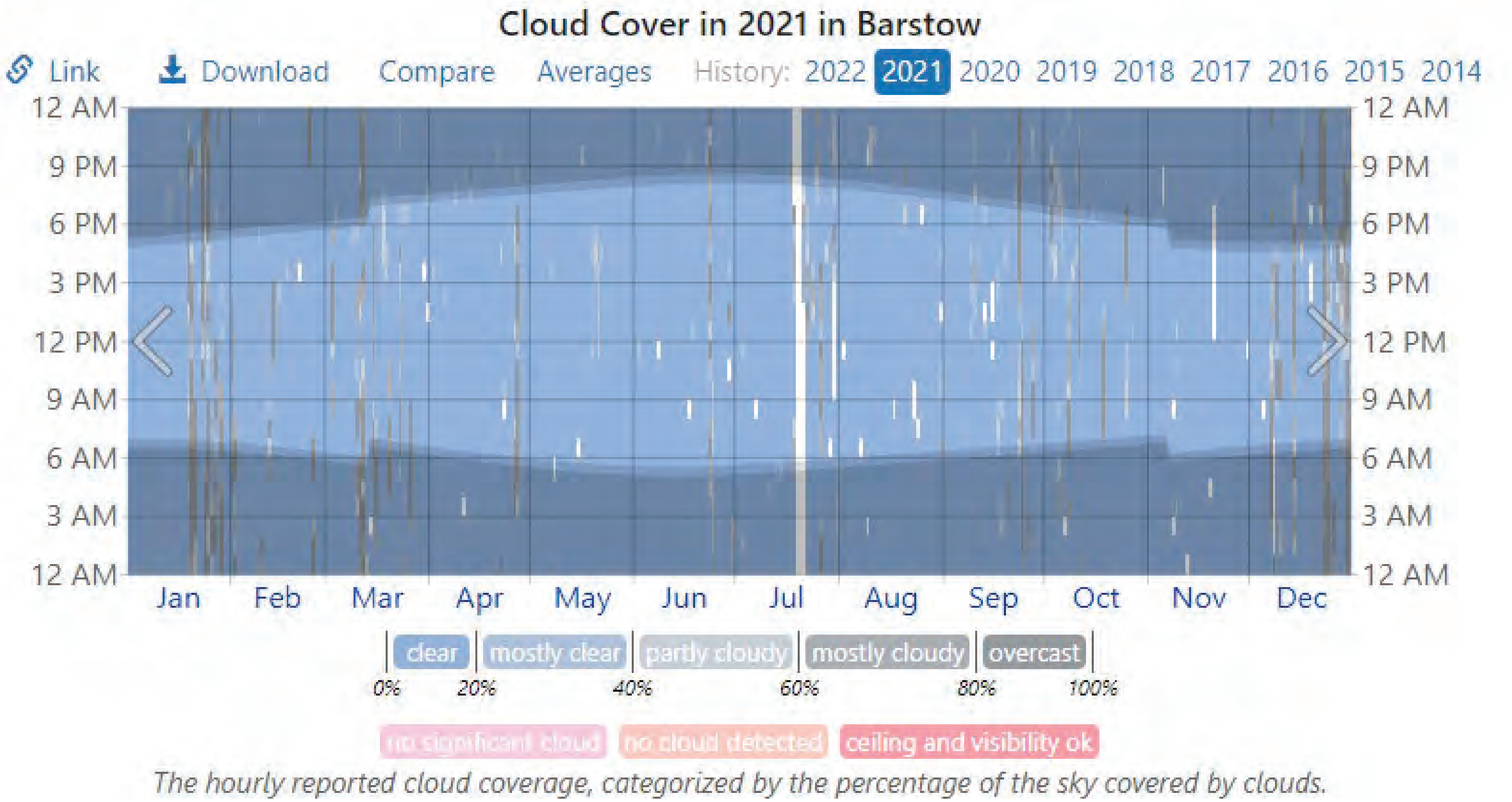


Figure 14: January 3-5, 2018 Solar Production vs Customer Demand