Revision Two

IMM Quarterly Markets Performance Report

Summer 2024 Report Highlights

June 2024 – August 2024 outcomes

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Summary for Summer 2024

- **Wholesale market costs** totaled $1.94bn, a 21% increase (up $0.34bn) on Summer 2023 costs of $1.61bn, driven by higher energy and capacity costs
  - Energy market costs made up 80% of total wholesale costs; capacity costs made up 17%
- Higher **energy costs** (totaled $1.56bn, up by $0.32bn or 26%), driven by higher loads and greater reliance on peaking capacity
  - Avg. day-ahead and real-time **Hub LMPs** were $39.03 and $37.45/MWh; up 9-14% from Summer 2023
  - Avg. **natural gas price** of $1.80/MMBtu, down 21% on the Summer 2023 price of $2.30/MMBtu, continuing the trend of lower gas prices since early 2023
  - Avg. loads up by 5% and peak load up by 8% compared to Summer 2023 due to hotter weather
  - Capacity scarcity conditions occurred on June 18 & Aug 1 due to high loads and generator trips
    - RT LMPs peaked at $2,634/MWh (Aug 1); pay-for-performance credits/charges totaled $13.9m for the Jun 18 event and $48.8m for the Aug 1 event
- **Capacity market costs** were up by 31% (totaled $337m, up by $80m) on Summer 2023 due to higher clearing prices in FCA 15 (held in Feb. 2021)
  - Clearing price of $2.61/kw-mo for rest-of-system, compared to the FCA 14 price of $2.00/kW-mo; due to the increase in the capacity requirement and resource retirements

Summary for Summer 2024 (cont.)

- **Real-time reserve payments** were $23.9m, much higher than the $3.7m total in Summer 2023 due to longer duration capacity scarcity conditions
  - *Non-spinning reserve* (10- and 30-min offline products) payments totaled $12.1m, up $10.8m on prior summer
    - 51 hours of 10-min non-zero pricing (avg. price of $181/MWh) and 31 hours of 30-min (avg. price of $212/MWh) pricing throughout the quarter; frequency of non-zero pricing 10x greater than last summer but lower avg. prices
  - *Spinning reserve* (10-min) payments totaled $11.8m, up $9.4m on prior summer
    - 216 hours of non-zero spinning pricing, similar to last summer; avg. non-zero price of $48.57/MWh, up from $13.30/MWh due to spinning prices incorporating more frequent TMNSR & TMOR pricing
- Total **regulation payments** were $6.1m, similar to Summer 2023 payments ($6.4m)
  - Slight decrease resulted from lower capacity prices (down 6%); capacity prices decreased due to a decline in regulation offer prices, as alternative technology regulation resources continue to make up a larger share of regulation mix
- Uplift or **Net Commitment Period Compensation** (NCPC) costs totaled $13.3m, up 96% (or $6.5m) on the prior summer due to increased economic first contingency payments to fast-start resources
  - Uplift costs represented 0.9% of the total energy costs
  - Uplift to economically committed and dispatched resources made up 90% ($12.0m) of the total, with most local reliability payments at the distribution level
  - Level of uplift to fast-start resources when dispatched during peak times is large given that the fast-start mechanics are intended to better reflect the commitment and dispatch costs in the energy price; we are evaluating the causes of this outcome

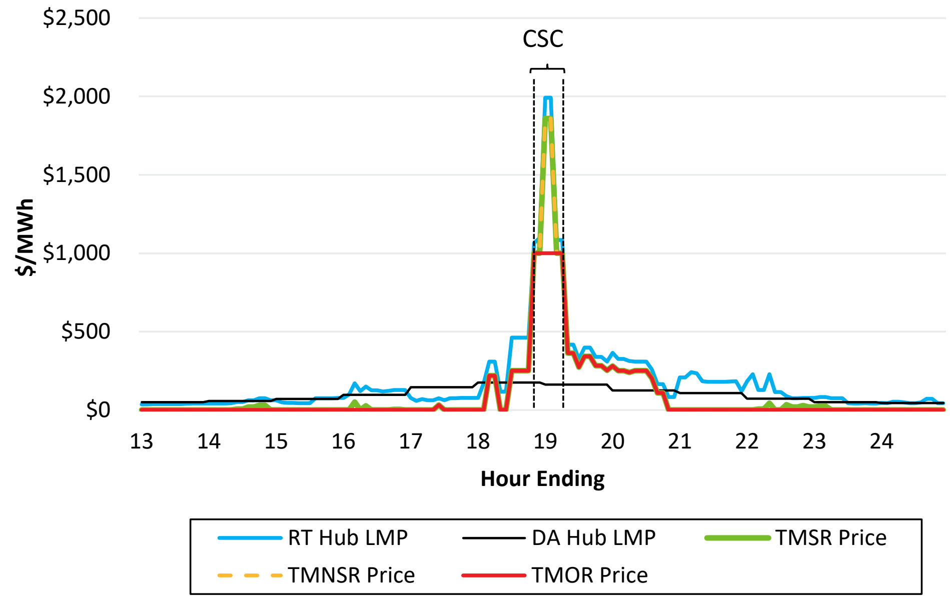
Summary for Summer 2024 (cont.)

- Two **Capacity Scarcity Conditions** during the summer due to operating reserve deficiencies caused by generator outages [Slides 5-8]
  - Events were transient in nature and reserve deficiencies were between 6% and 24% of the total requirement; lasting 2 hours 20 minutes combined
  - Total payments/charges of ~$47m, 20% of base capacity payments based on a performance payment rate of $5,455/MWh
  - Generally, resources that were uneconomic in the day-ahead market with long-lead times under-performed during the events
- Energy market outcomes were competitive, energy supply mitigation was infrequent and there was no evidence of impactful capacity withholding overall [Slides 16-17]
- **Forward Reserve Auction** for winter 2024/25 was structurally competitive; TMOR and TMNSR products both cleared at $1,999/MW-month, down on the summer auction. This was the last auction as the market will sunset with Day-Ahead Ancillary Services in March 2025 [Slide 18]
- An assessment of the **Do-Not-Exceed Dispatch rules for Solar** indicates increased participation in the Day-Ahead Energy market; these *wholesale-participating* resources are now incorporated into the economic dispatch and pricing process, with must offer obligations for capacity resources [Slides 19-20]
  - Curtailment of solar resources remains infrequent as these resources are generally located in unconstrained transmission areas

June 18 Capacity Scarcity Conditions

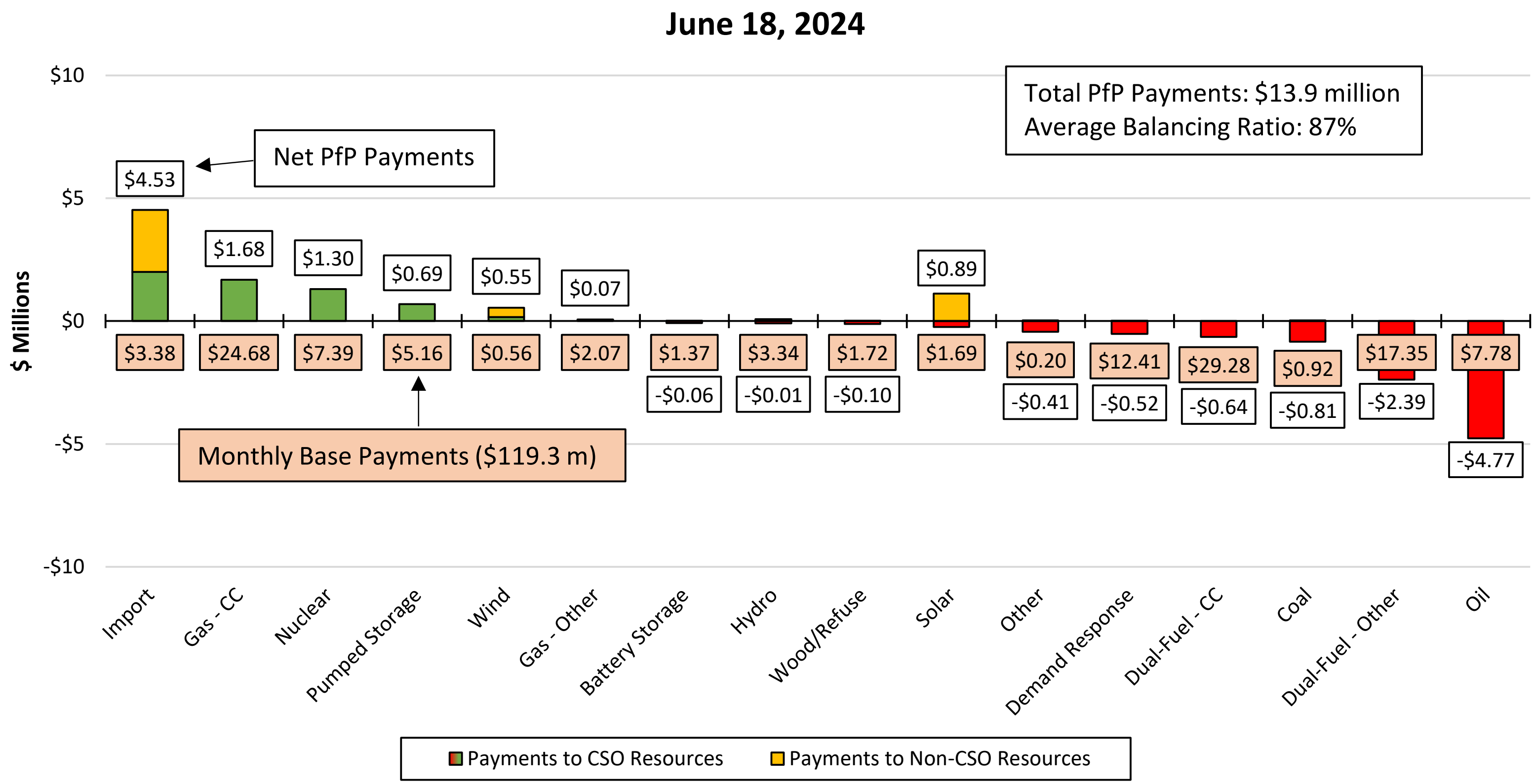
- Hot day with temperatures peaking at 89°F during HE 18, loads peaking at 22,446 during HE 19
- Unplanned generator outage during the evening peak resulted in a loss of 560 MW
  - Three other generators tripped throughout the day and remained unavailable/reduced during evening peak, leading to a loss of 745 MW
- Reserve deficiency but sufficient energy supply to meet load: TMOR Penalty Factor ($1,000/MWh) in effect during intervals beginning 17:50-18:15 (30 min event)
- Real-time Hub LMP peaked at $1,993/MWh during the 18:00 & 18:05 intervals

Hub LMPs & Reserve Prices On June 18 (5-min)



Reserve Acronyms:
TMSR: ten-minute spinning reserve
TMNSR: ten-minute non-spinning reserve
TMOR: thirty-minute operating reserve

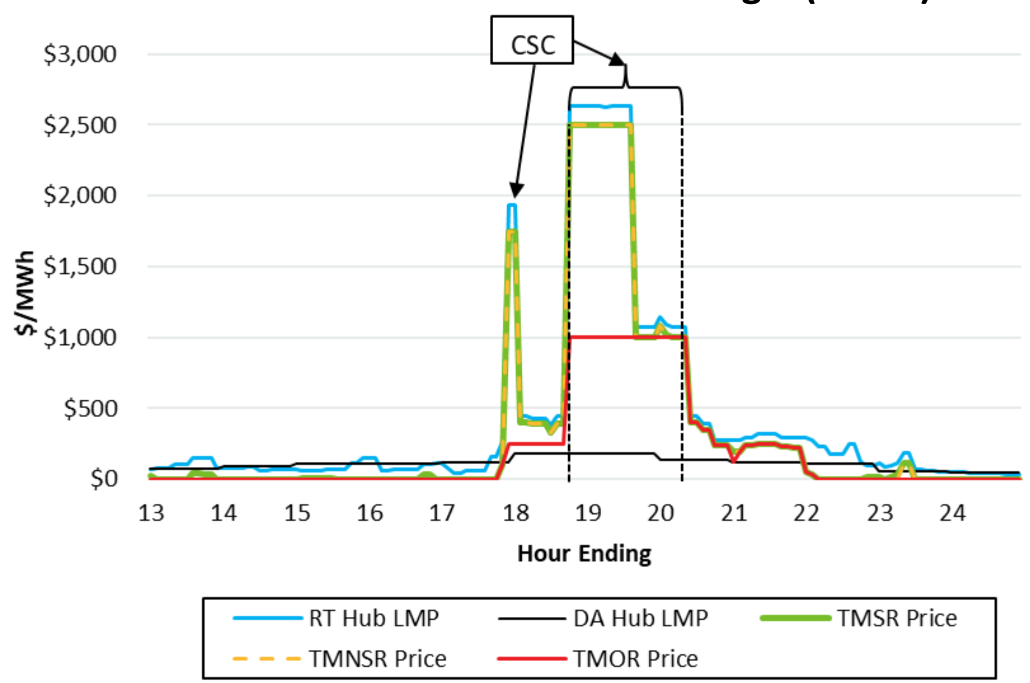
June 18 Pay For Performance credits and charges totaled $13.9m



August 1 Capacity Scarcity Conditions

- Temperatures peaked at 90°F during HE 17, loads peaked at 23,758 MW during HE 18
- A generator tripped at 16:44, resulting in a loss of 330 MW just before the evening peak
  - Four other generators experienced unplanned outages/reductions due to mechanical problems throughout the day, resulting in a loss of about 380 MW
- Two distinct periods of operating reserve deficiency: TMNSR Penalty Factor ($1,500/MWh) in effect during 16:55-17:00 & 17:45-18:45 intervals, TMOR Penalty Factor ($1,000/MWh) in effect during 17:45-19:20 intervals (110 min event)
- Real-time Hub LMP peaked at $2,634/MWh during the 18:00-18:10 intervals

Hub LMPs & Reserve Prices On Aug 1 (5-min)



<u>Reserve Acronyms:</u>
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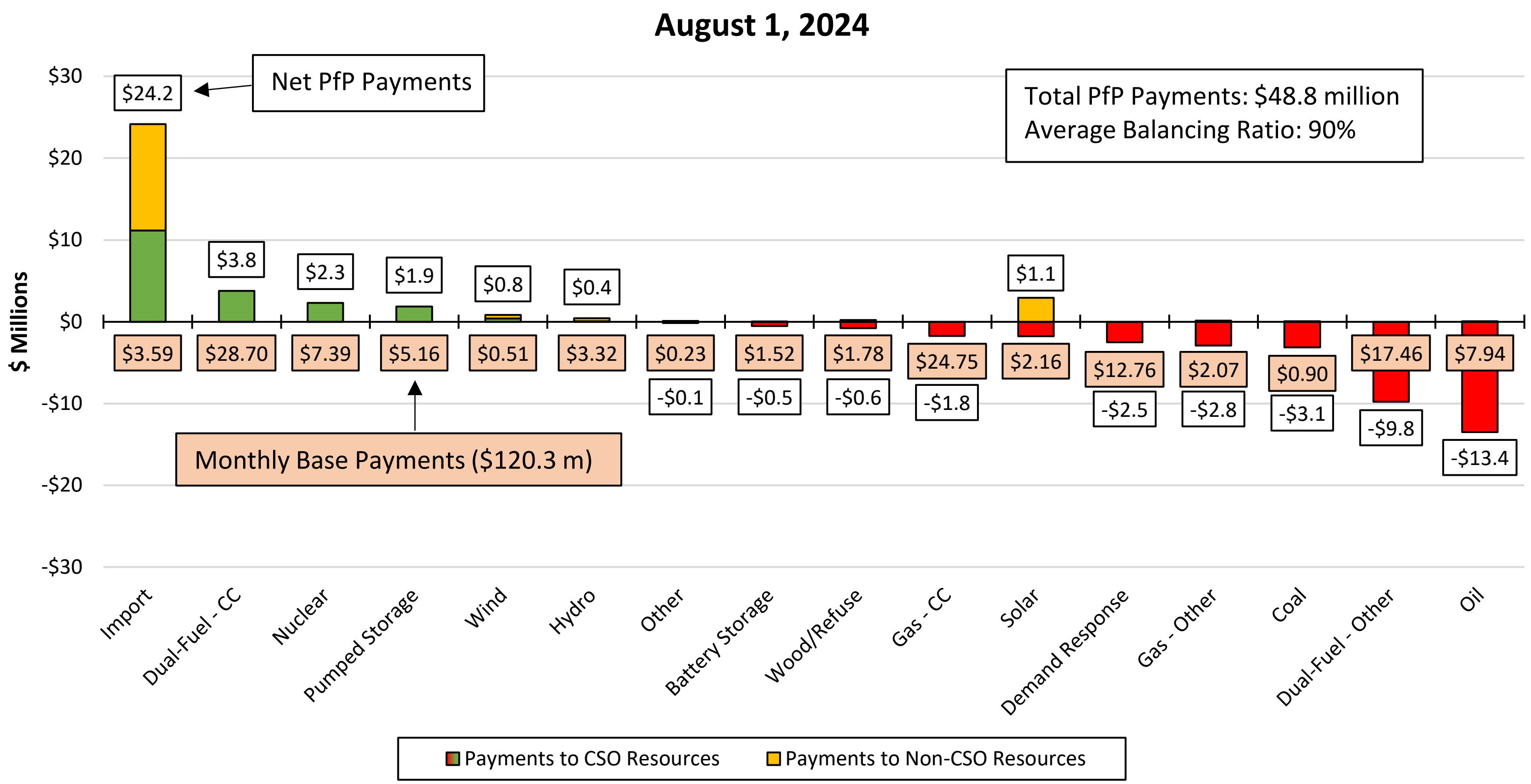
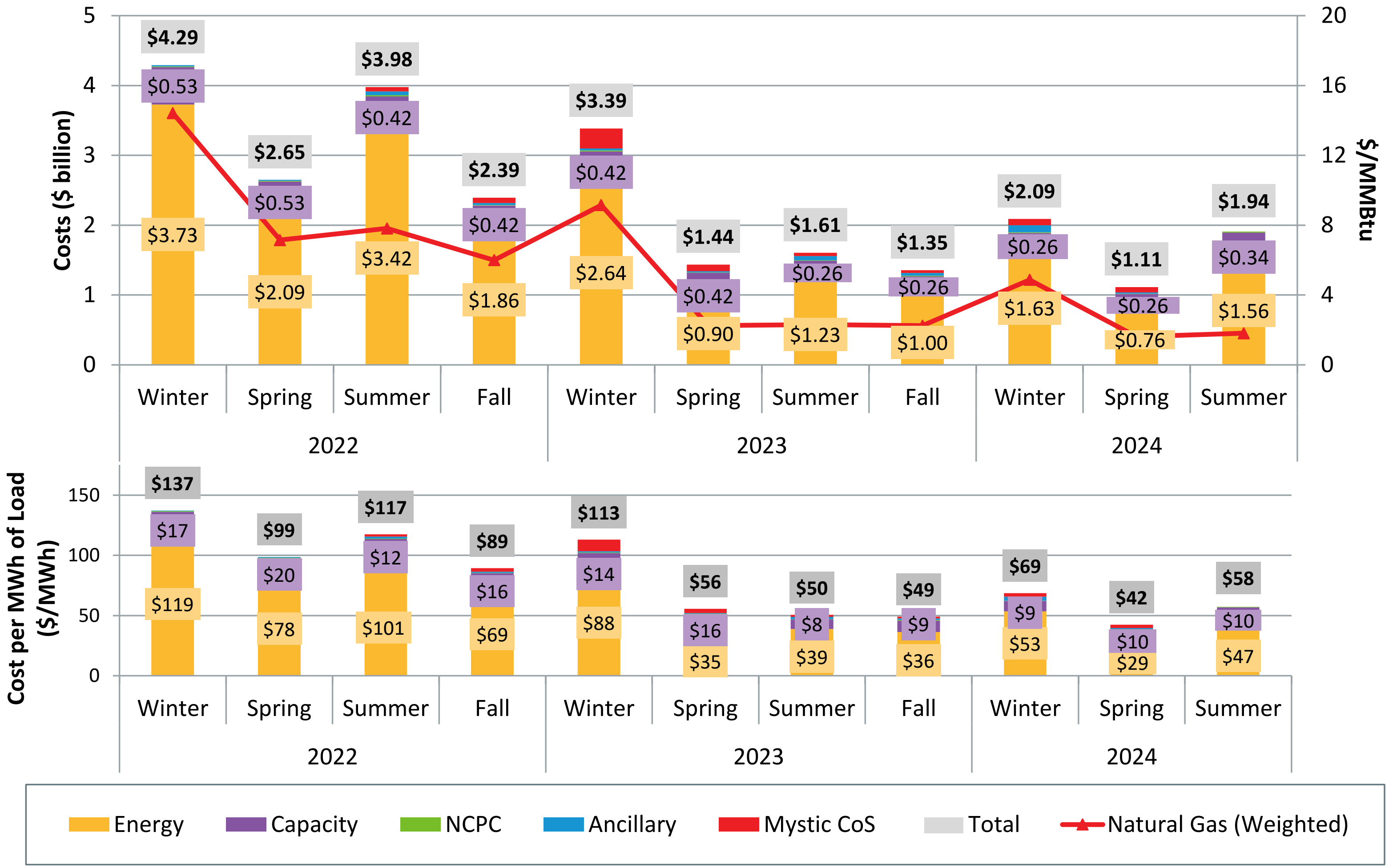
August 1 Pay For Performance credits and charges totaled $48.8m



Seasons: Winter: Dec-Feb Spring: Mar-May **Summer: Jun-Aug** Fall: Sep-Nov

Wholesale costs up ~21% on prior summer; higher loads led to increased energy costs despite lower gas prices



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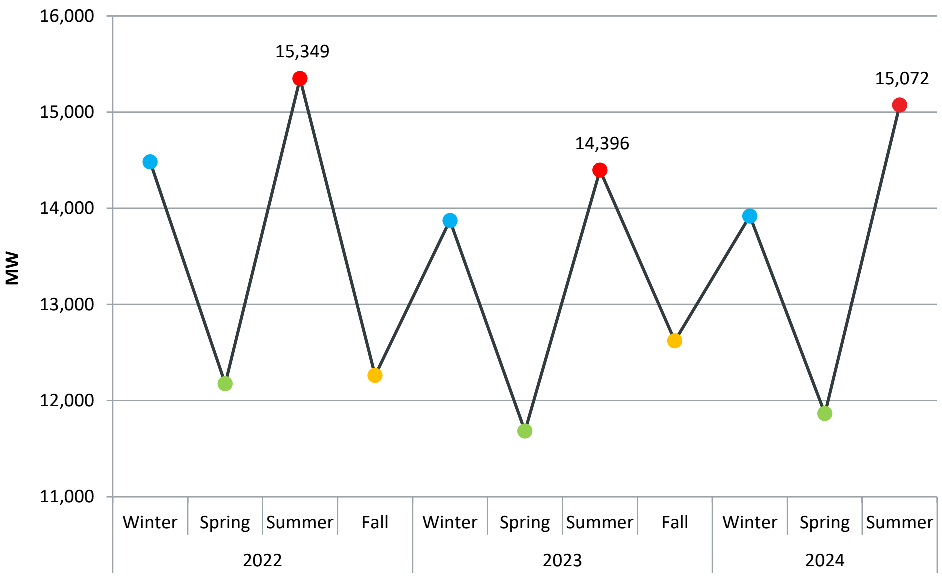
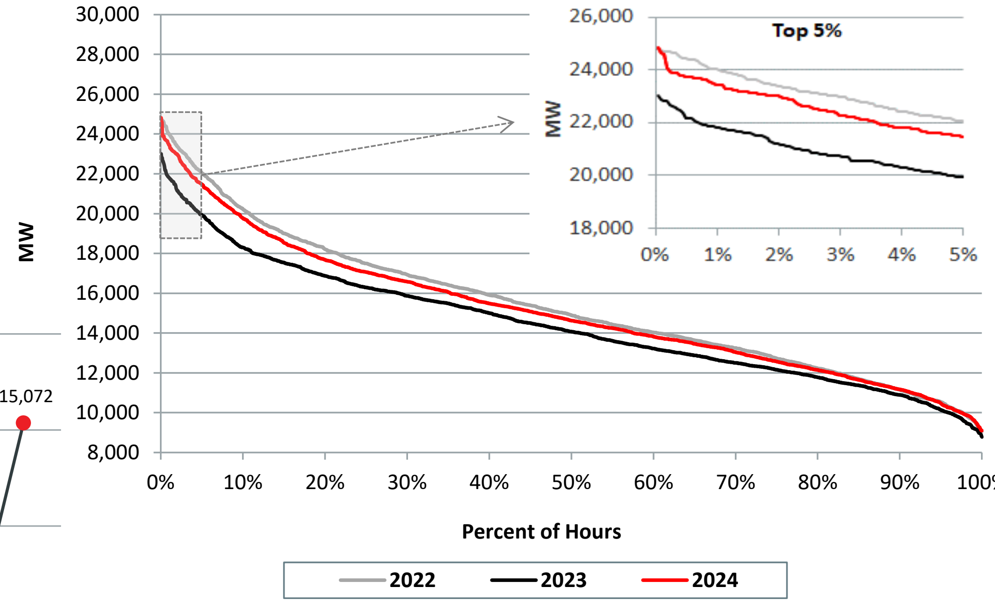
Higher average and peak loads compared to previous summer due to hotter weather conditions

Average Hourly Load



Load Duration Curves



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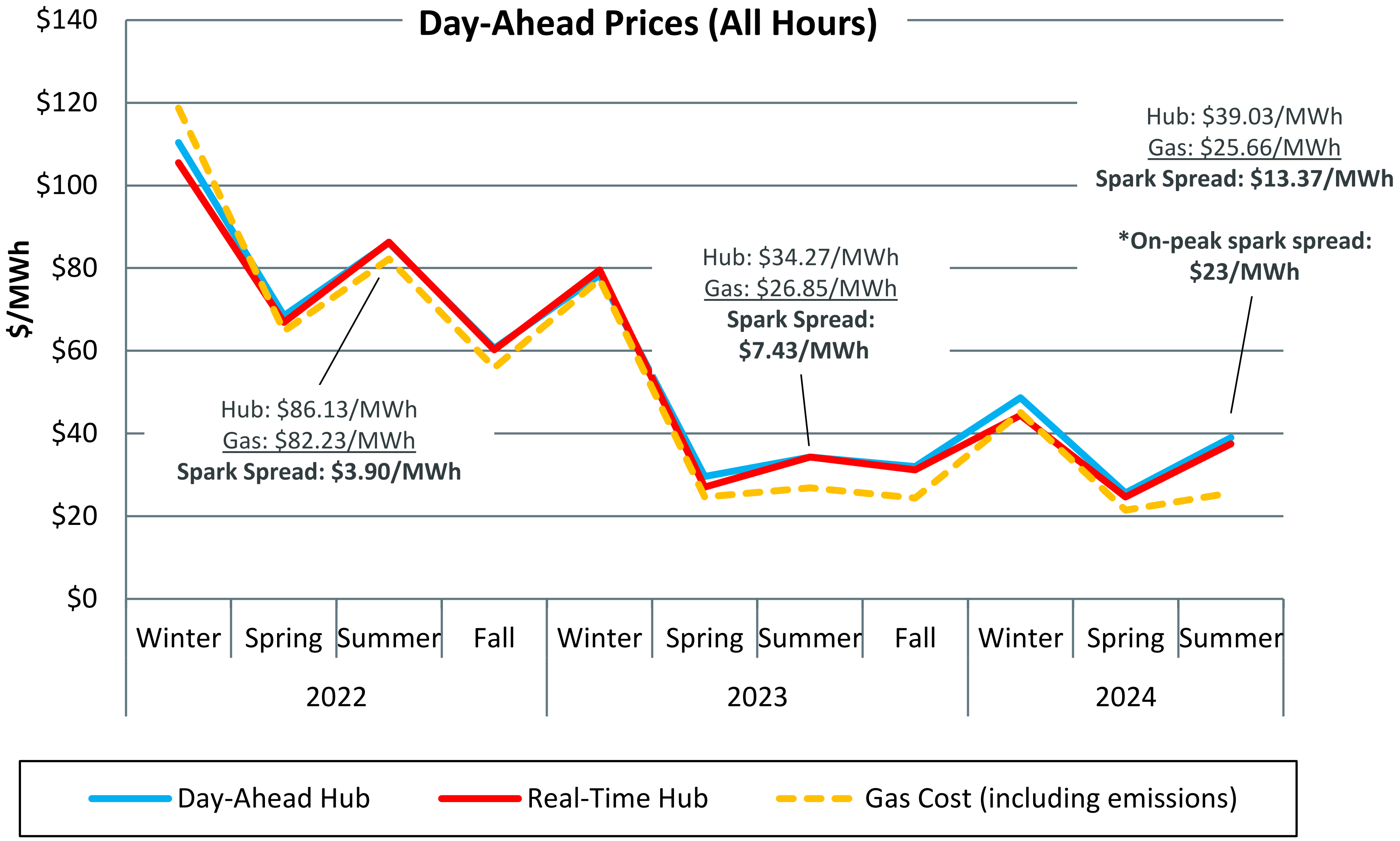
Higher LMPs despite lower gas prices; higher loads led to increased use of gas resources in upper dispatchable ranges



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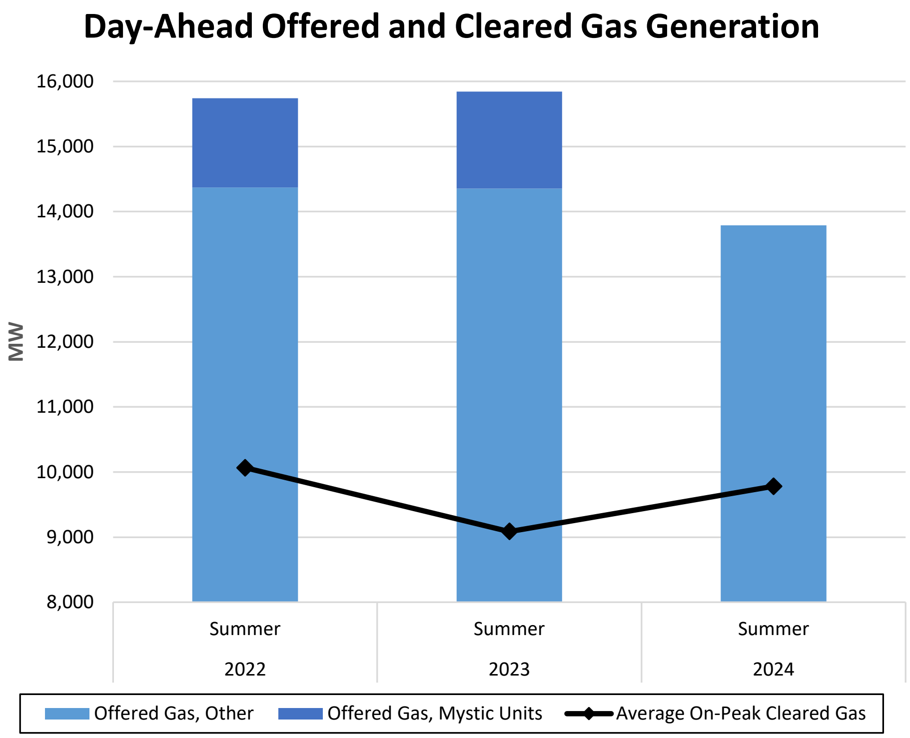
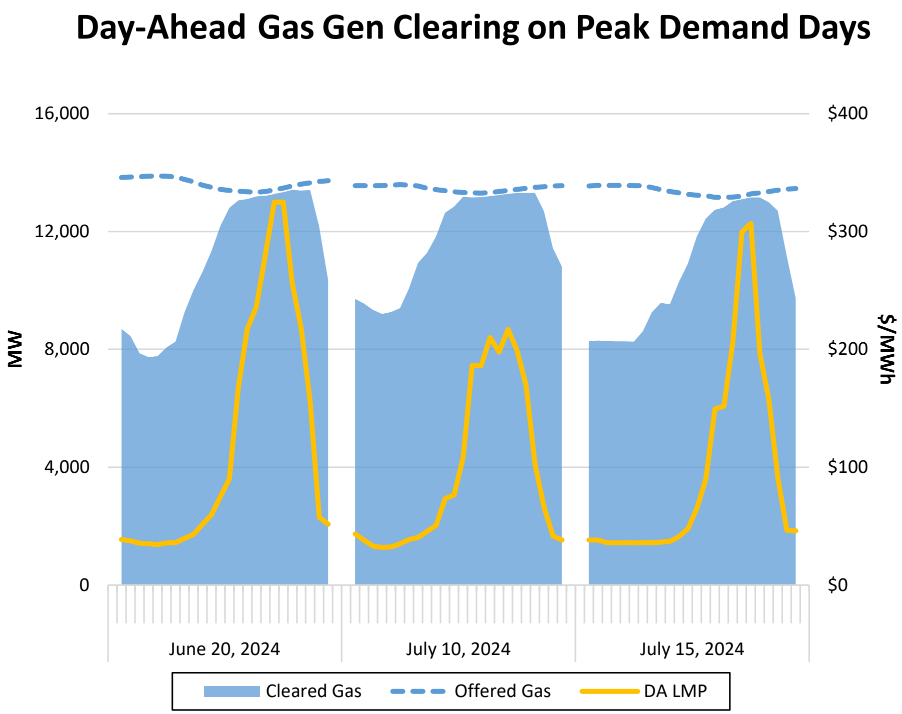
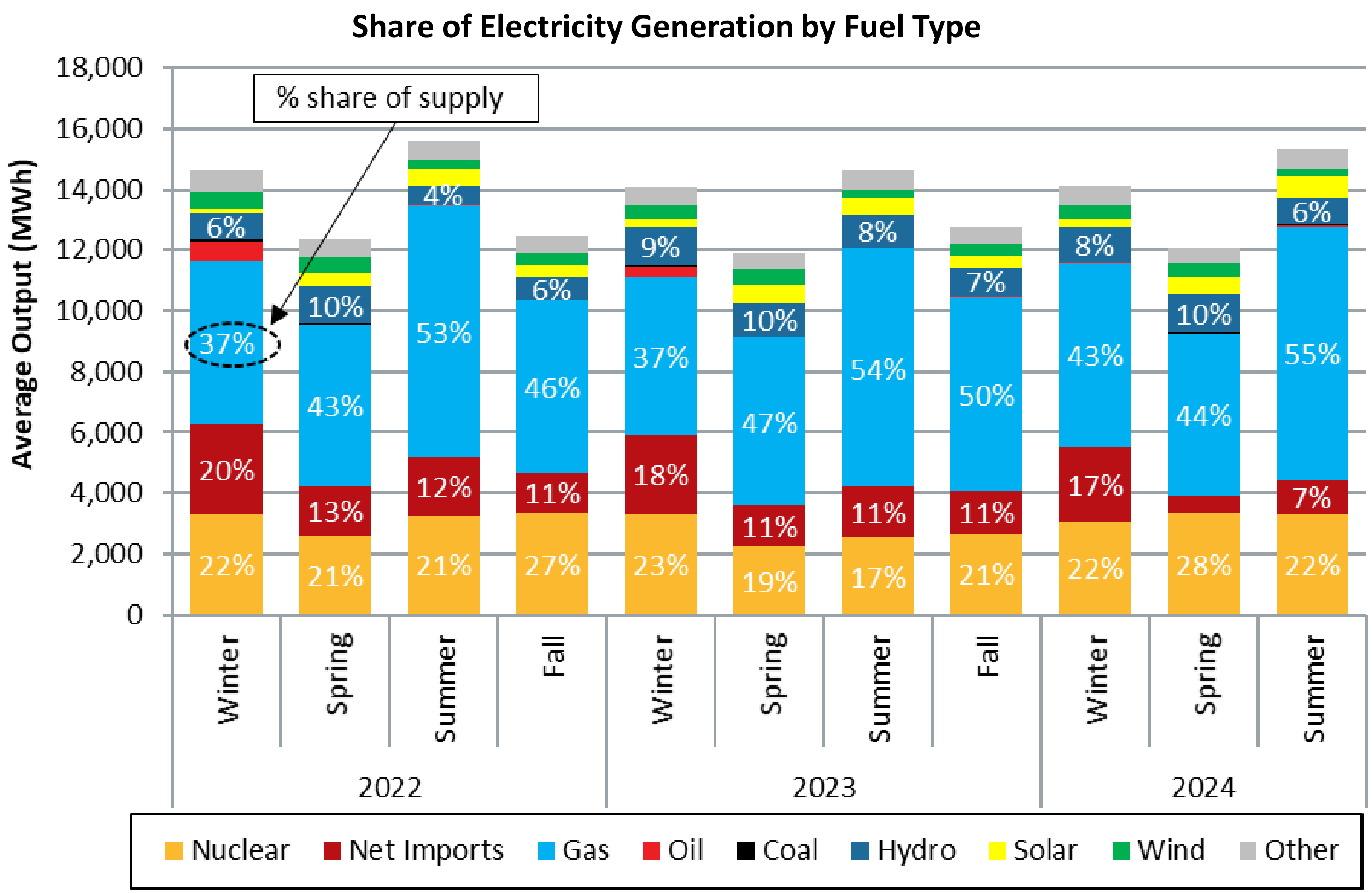
Available gas-fired generation down on Mystic retirement; max utilization of available capacity during high demands days into expensive duct-firing range



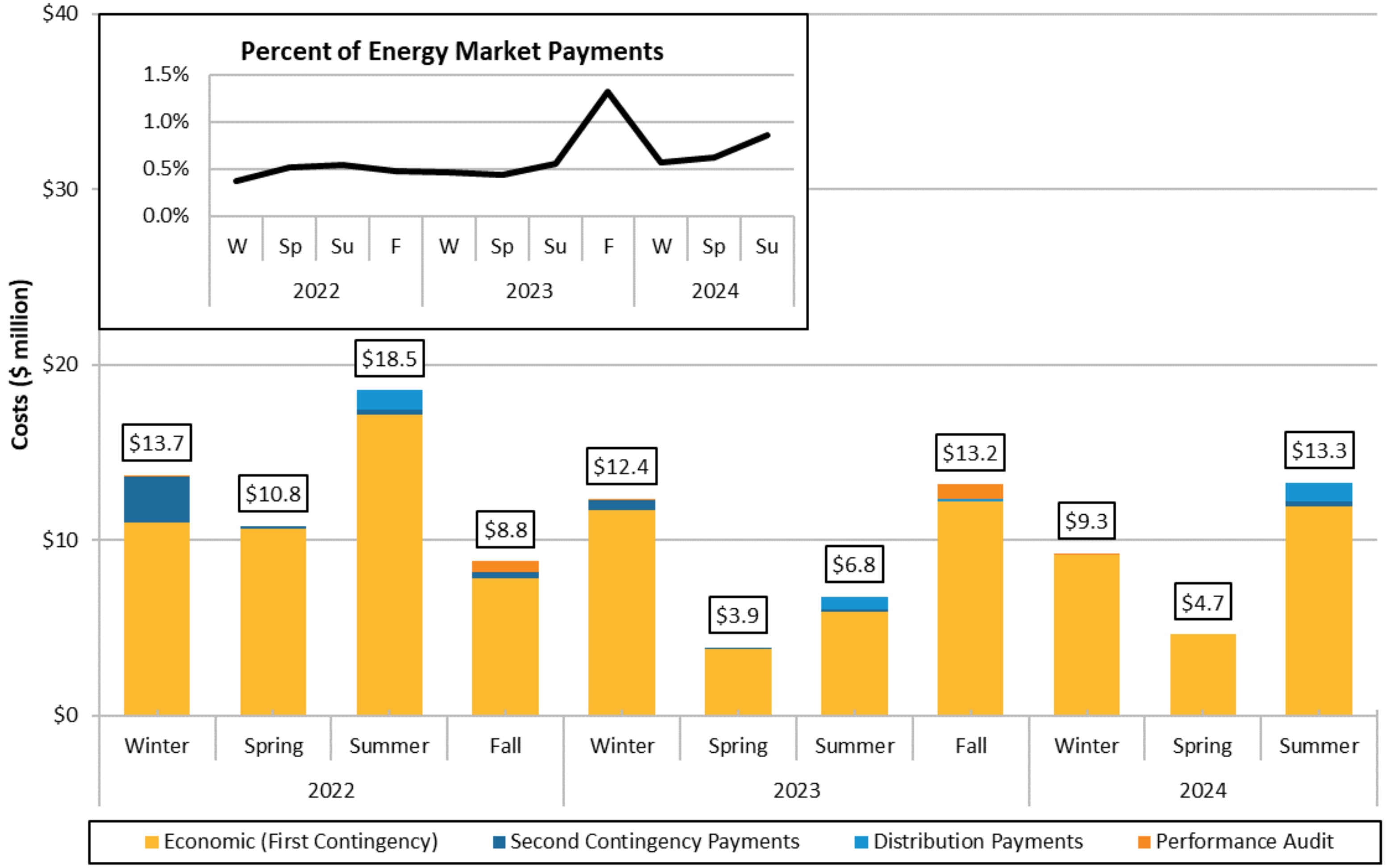


Higher loads in Summer 2024; net imports slightly up from historic low in Spring 2024



Seasons: Winter: Dec-Feb Spring: Mar-May **Summer: Jun-Aug** Fall: Sep-Nov

Uplift payments remained low but increased from last year due to higher first contingency payments to fast-start resources



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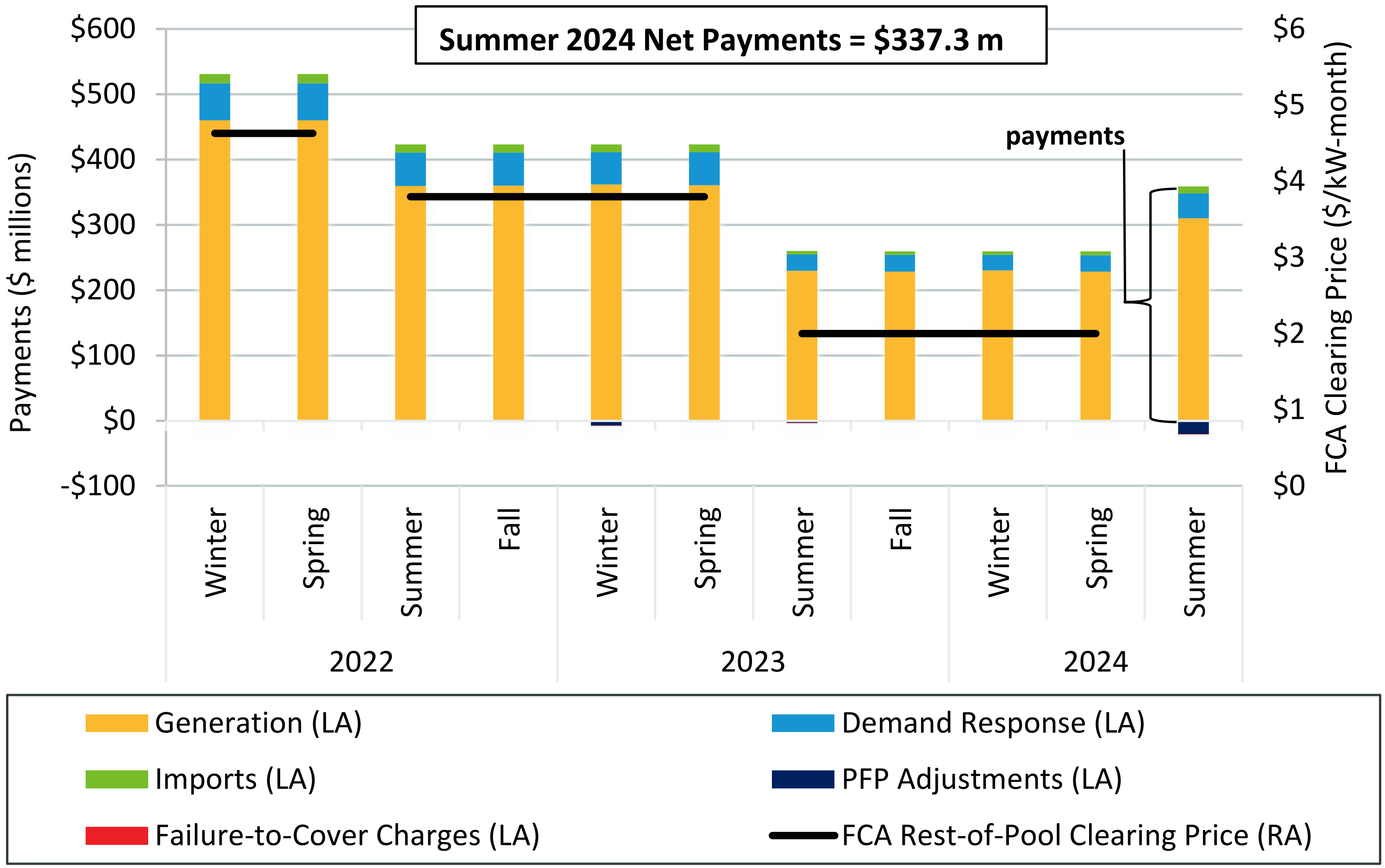
First quarter of FCA15; higher clearing prices

FCA 15 prices: $2.61/kW-month; 30% higher than the previous year



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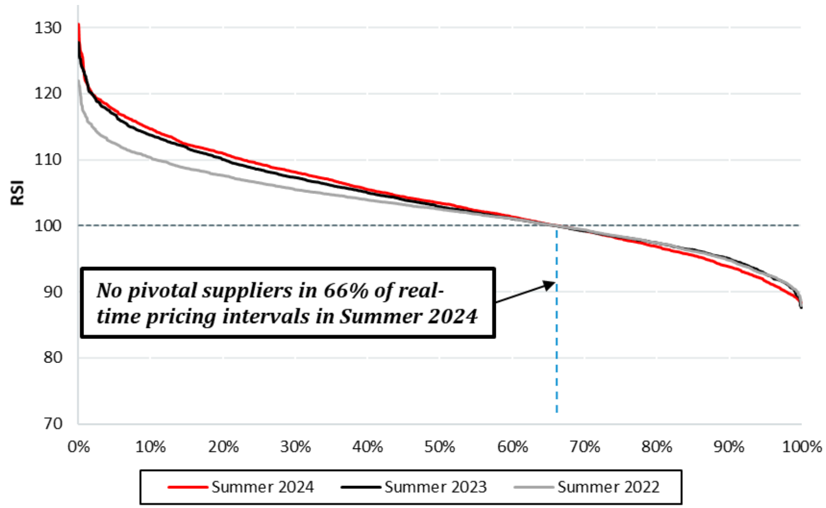
Energy Market Competitiveness

- Energy market structurally uncompetitive at times, but pricing outcomes were competitive; energy supply mitigation was infrequent (next slide) and overall, there was no evidence of impactful capacity withholding
- Structural market power metrics indicate similar reliance on the largest supplier as previous 2 summers
- The residual supply index (RSI) for the real-time market in Summer 2024 was 104, indicating that on average, the ISO could meet load and the reserve requirement without energy and reserves from the largest supplier
- However, there was at least one pivotal supplier present (RSI < 100) for 34% of 5-minute intervals

Residual Supply Index and Intervals w/Pivotal Suppliers (RT)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%

System-Wide Residual Supply Index Duration Curves



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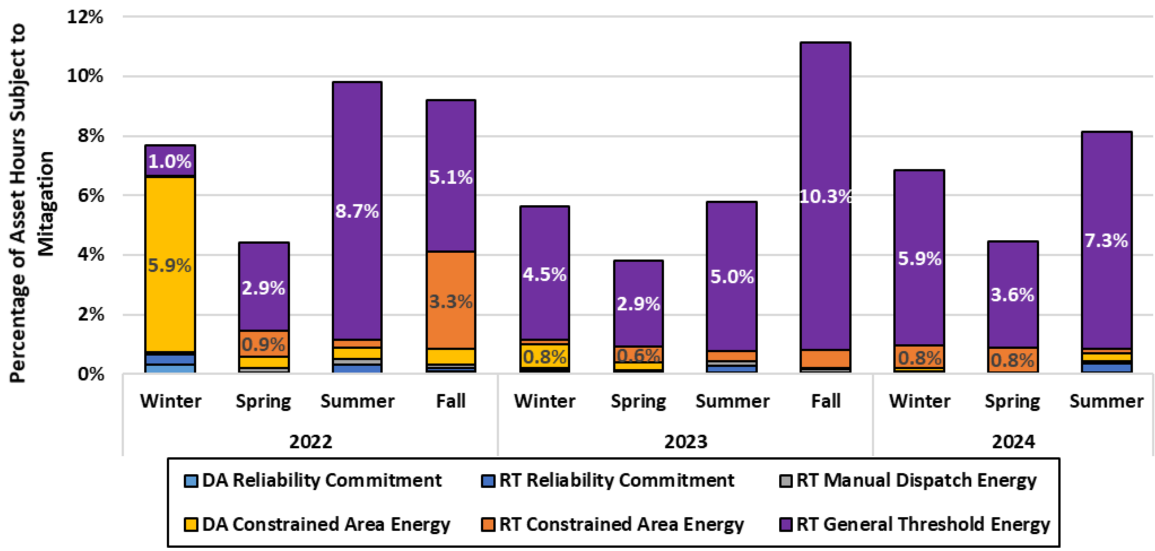
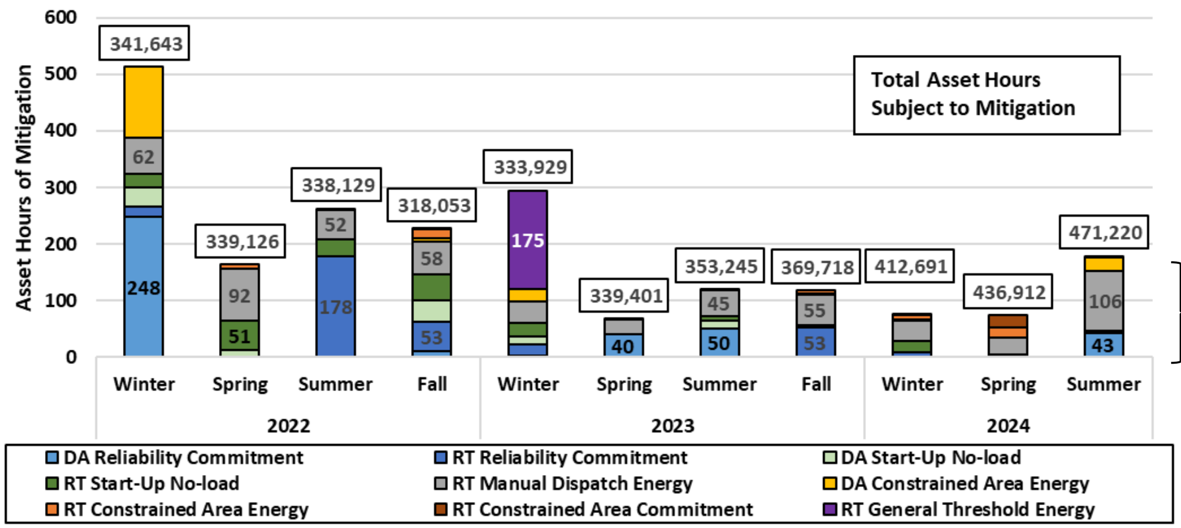
Market Power Mitigation in the Energy Market

- In general, mitigation occurs very infrequently relative to the structural test failures



8.2% of total asset-hours flagged for market power, mostly at the system level (purple bar)



Just 0.04% (or 179 asset-hours) of total asset-hours were mitigated

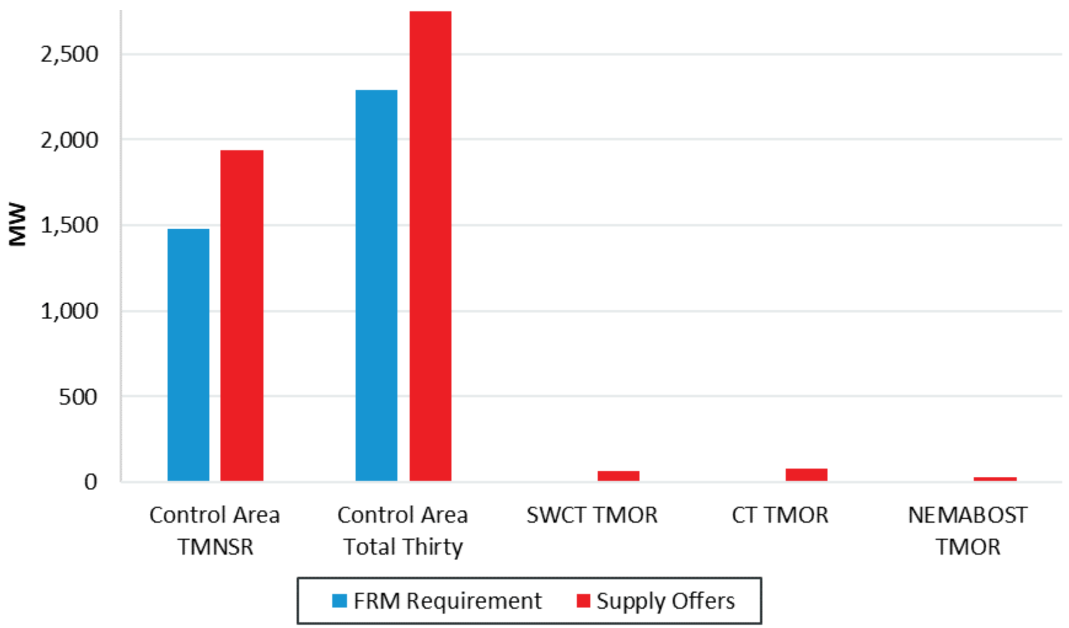
Seasons: Winter: Dec-Feb Spring: Mar-May **Summer: Jun-Aug** Fall: Sep-Nov

Forward Reserve Auction for winter was structurally competitive; FRM to sunset given DASI implementation

FRM Auctions, RSI and Clearing Prices for TMNSR and TMOR

Procurement Period	Offer RSI TMNSR (System-wide)	TMNSR Price	Offer RSI Total Thirty (System-wide)	TMOR Price
Summer 2022	78	$7,386	90	$499
Winter 2022-23	109	$2,500	112	$439
Summer 2023	81	$7,499	86	$7,499
Winter 2023-24	82	$3,350	89	$671
Summer 2024	107	$2,952	103	$2,952
Winter 2024-25	106	$1,999	102	$1,999

Forward Reserve Requirements & Supply Offer Quantities



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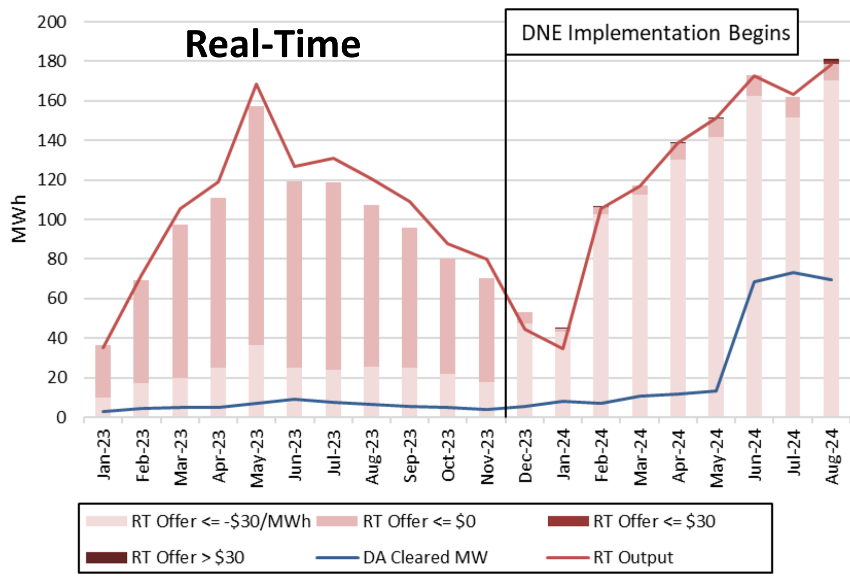
Solar Do-Not-Exceed (DNE) Dispatch Rules

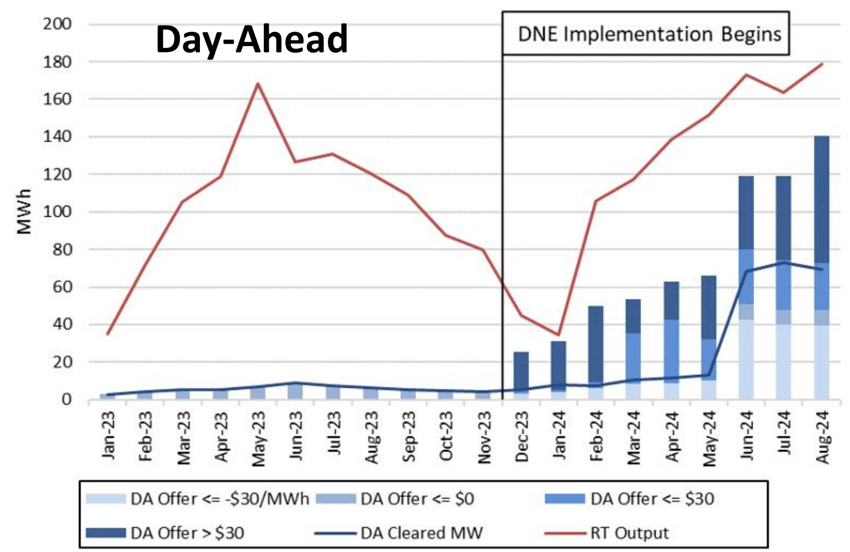
- Front-of-the-meter (FtM) solar generators became subject to DNE Dispatch rules beginning Dec 5, 2023
- With DNE, solar resources compete based on price when limited by transmission constraints
  - Such rules already apply to wind and run-of-river hydro generators
- 'Must Offer' requirement is applicable to resources with a capacity supply obligation
  - Dispatchable solar generators must offer their expected output in both the DA and RT energy markets

Concept	Value	% Total
Count of FtM PV Generators	58	-
Total Summer Max Net Output (MW)	807	-
Subset: PV currently on DNE Dispatch (MW)	699	87%
Subset: PV associated with FCM Resource (MW)	564	70%
Subset: PV on DNE *and* associated with FCM Resource (MW)	531	66%

Solar DNE resources respond with reduced offer prices

- Change in **Real-Time Market** offer behavior since DNE rollout, with solar resources reducing offers in order to be competitive should network capacity be limited
  - Curtailment of solar due to binding transmission constraints is infrequent
- Solar DNE has increased the quantity of offered and cleared capacity in the **Day-Ahead Market**, helping alignment with physical dispatch in real-time
  - Cleared virtual supply at solar nodes have decreased as a result





Questions