Day-Ahead Market Enhancements

Stakeholder Working Group Meeting
August 13, 2019

Megan Poage & Don Tretheway
Market Design Policy

Agenda

Item	Time	Presenter
Welcome	10:00 – 10:10 AM	Kristina Osborne
Need for day-ahead market redesign	10:10 – 10:45 AM	Megan Poage
Policy alignment	10:45 – 11:00 AM	Megan Poage
Market formulation alternatives	11:00 AM – 12:00 PM	Megan Poage
Lunch	12:00 – 1:00 PM	
Data analysis	1:00 – 1:30 PM	Bridget Clark
Comparison of market alternatives	1:30 – 3:30 PM	Don Tretheway
Next steps	3:30 – 3:45 PM	Kristina Osborne

Day-Ahead Market Enhancements

NEED FOR DAY-AHEAD MARKET REDESIGN

Megan Poage
Sr. Market Design Policy Developer
Market Design Policy

Day-ahead market enhancements will improve market efficiency in addressing net load uncertainty

- Uncertainty between day-ahead and real-time market has increased from 2017 to 2019
- Historically, generators had higher certainty to know if they would be scheduled in real-time
- Due to uncertainty and changing resource fleet, commitment decisions are no longer necessarily known
- Gas, hydro, storage, and imports need to cover costs to be available for dispatch in real-time – this will be accomplished with imbalance reserves

Load forecast adjustments and out-of-market actions are not co-optimized with energy in the day-ahead market

- CAISO operators need to address uncertainty needs
  - Currently accomplished with load forecast adjustments and exceptional dispatches
- The load forecast adjustment process is a blunt and inefficient tool to meet reliability needs
  - May not commit additional resources, may merely increase the RUC schedule for a resources that's already online
  - RUC doesn't ensure sufficient ramping speed
- A market product priced at marginal cost will more efficiently recognize the value of capacity thereby appropriately compensating flexible resources
  - Can be co-optimized with other day-ahead products

Resource adequacy on its own is not the most efficient way to meet changes between the day-ahead and real-time market

- Day-ahead market needs to correctly commit and position resources to provide upward and downward ramp capability in the real-time market

- Imbalance reserves will allow the CAISO to efficiently manage the RA fleet by creating a real-time market must offer obligation

- Imbalance reserves will cover the incremental cost of making capacity available between the day-ahead and real-time market that is currently embedded in the RA contracts

Real-time flexible ramping product is insufficient to address uncertainty that materializes between day-ahead and real-time

- Real-time market is unable to commit long start resources
- Short start gas units have costs to line up gas to be able to provide upward or downward ramp capability
- Imports may not be available after the day-ahead market
  - Transmission may be unavailable in real-time
  - May sell energy elsewhere (bilateral market) if not scheduled in the day-ahead market
- Amount of imbalance reserves needed to meet day-ahead to real-time uncertainty is greater than the amount of flexible ramping product needed for real-time market uncertainty
- Economic bids are needed to clear the flexible ramping product in the real-time market

Imbalance Reserves are different than Real-Time Flexible Ramping Product

Imbalance Reserves

- Hourly product
- 15-minute dispatchable
- Biddable
- Covers granularity difference <u>and</u> uncertainty between DAM and FMM
- All awards are co-optimized and settled simultaneously
- DAM has no energy price formation issue because the market solves all hours in a single optimization
- Stepped relaxation parameters (proposed)

RT Flexible Ramping Product

- 15-minute product
- 5-minute dispatchable
- Not biddable
- Covers uncertainty from FMM to RTD to Real Time
- Awards are calculated in successive runs and are only settled from the binding to the first advisory interval
- Forecasted movement addresses energy price formation issues due to rolling time horizon
- Demand curve for uncertainty

Since these are two separate products, the ISO proposes no deviation settlement between them

Day-Ahead Market Enhancements

POLICY ALIGNMENT

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Sr. Market Design Policy Developer
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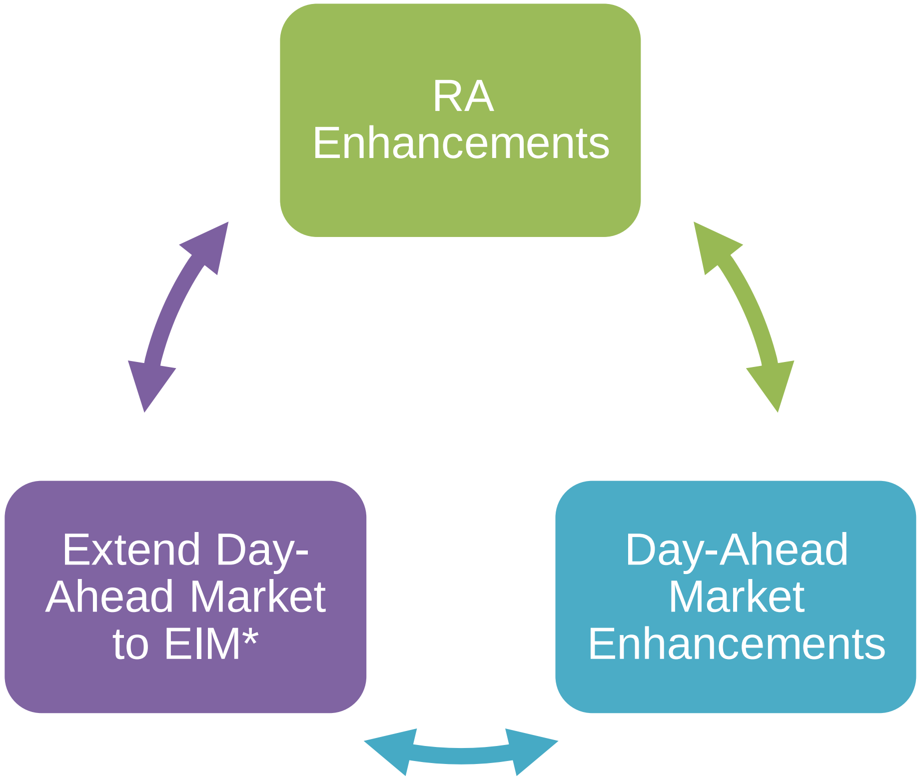
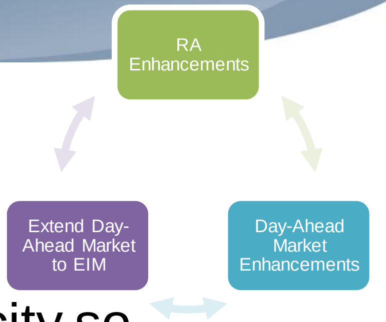
The CAISO will be implementing RA Enhancements, DAME, and EDAM* simultaneously in Fall 2021



Need to consider interactions between initiatives during policy development

* Commencing initiative is dependent upon feasibility assessment

Each effort has a specific goal and purpose



Resource Adequacy ensures forward procurement of capacity so adequate supply is available and bid in to meet CAISO's load and reliability requirements

- **RA Enhancements** will align the RA requirements with the transforming needs of the CAISO grid

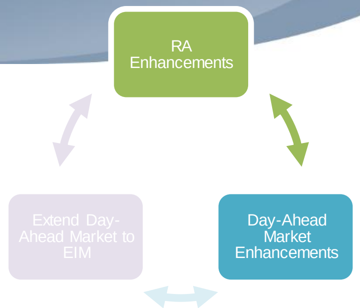
Day-Ahead Market co-optimizes energy and ancillary services to meet daily load and reliability requirements

- **Day-Ahead Market Enhancements** introduces imbalance reserves to meet ramping and uncertainty needs between the day-ahead and real-time markets and appropriately compensate resources to be available for real-time dispatch

Regional Markets allow multiple entities to share resources across a larger footprint to capture diversity and efficiency benefits

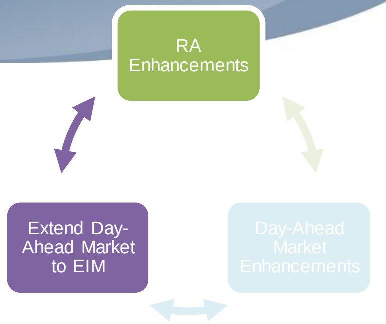
- **Extend Day-Ahead Market to EIM**, if commenced, will develop provisions to allow participation in the day-ahead market by EIM entities, e.g. recognizing different planning and procurement paradigms

RA Enhancements & DAME relationship



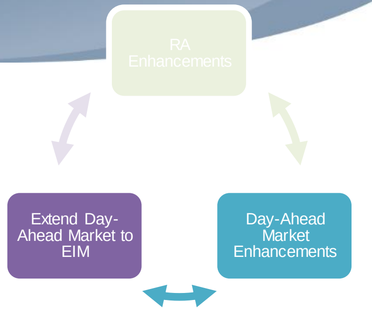
- RA establishes requirement to bid/self-schedule into the day-ahead market
- DAME proposes to introduce a real-time must offer obligation for awarded imbalance reserves
  - Imbalance reserves will replace the need for a resource adequacy real-time market must offer obligation
- Imbalance reserves will cover the incremental cost of making capacity available between the day-ahead and real-time market that is currently embedded in RA contracts

RA Enhancements & EDAM relationship



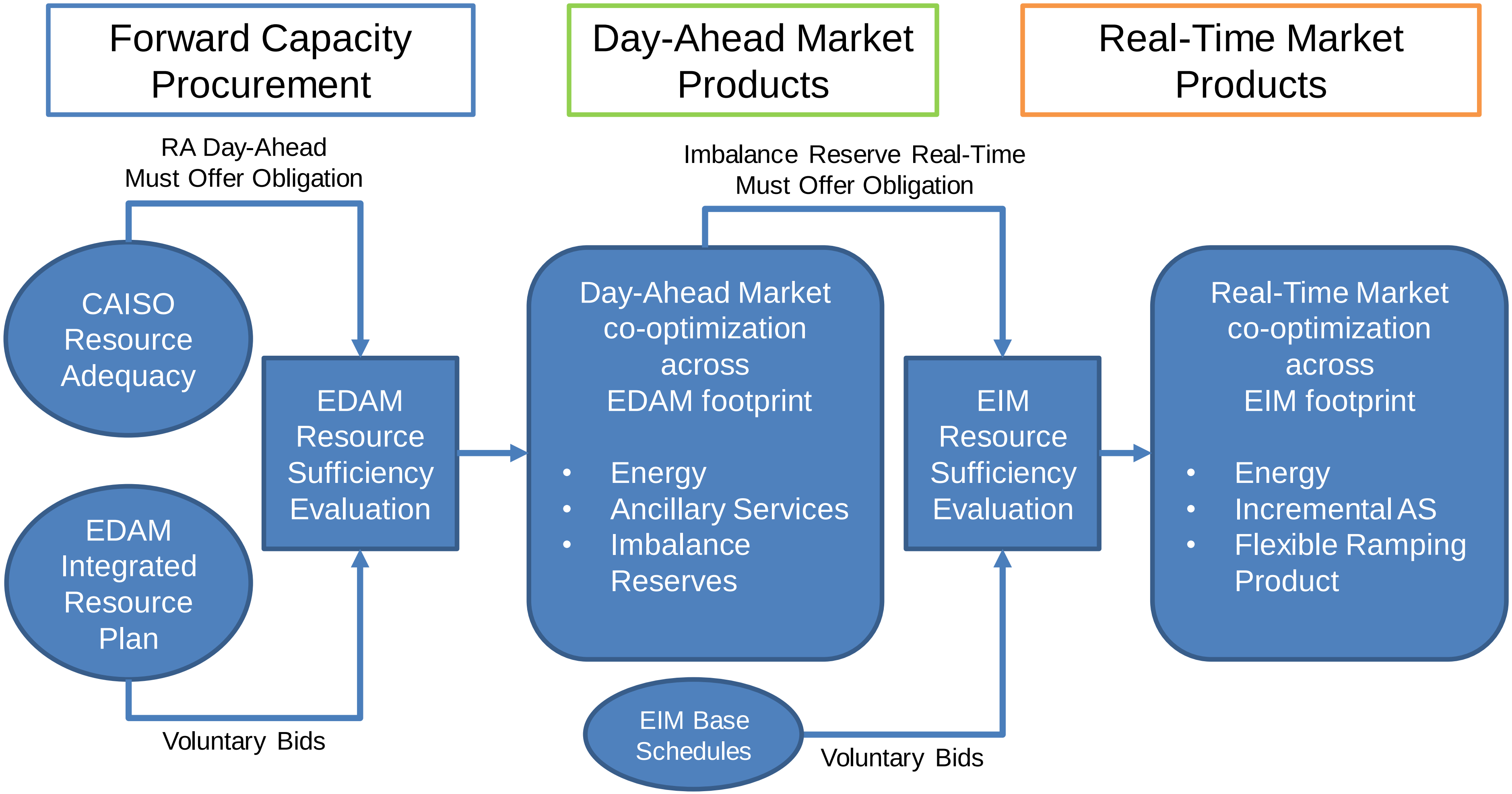
- Need to avoid double counting of resources in the resource sufficiency evaluation and in RA procurement
- RUC availability bids will be replaced with biddable imbalance reserves
- RA resources will not be required to provide imbalance reserve bids at $0 (as is done today for RUC) to enable efficient scheduling of capacity resources across the footprint

DAME & EDAM relationship



- Benefit of EDAM is to utilize resources in multiple EIM balancing authority areas to more efficiently meet load and operational needs
- Imbalance reserves are necessary to facilitate success of EDAM
  - Need to establish the resource sufficiency evaluation requirements
  - Enables efficient scheduling of energy/AS/imbalance reserves across the footprint
  - Identifies resources that are responsible for the real-time must offer obligation
- Imbalance reserves allow resources in one balancing authority area to be compensated when providing flexibility to another BA

Overview of RA, DAME & EDAM relationship with CAISO market runs



Day-Ahead Market Enhancements

POLICY DESCRIPTION OF MARKET FORMULATIONS

Megan Poage
Sr. Market Design Policy Developer
Market Design Policy

This presentation includes a qualitative description of the proposed day-ahead market formulations

- **Status Quo**: Sequential IFM + RUC

- **Financial (Option #1)**: Co-optimization of products based on bid-in demand

- **Financial + Forecast (Option #2)**: Co-optimization of products based on bid-in demand and CAISO forecast

Both proposed formulations will co-optimize the procurement of energy and capacity products

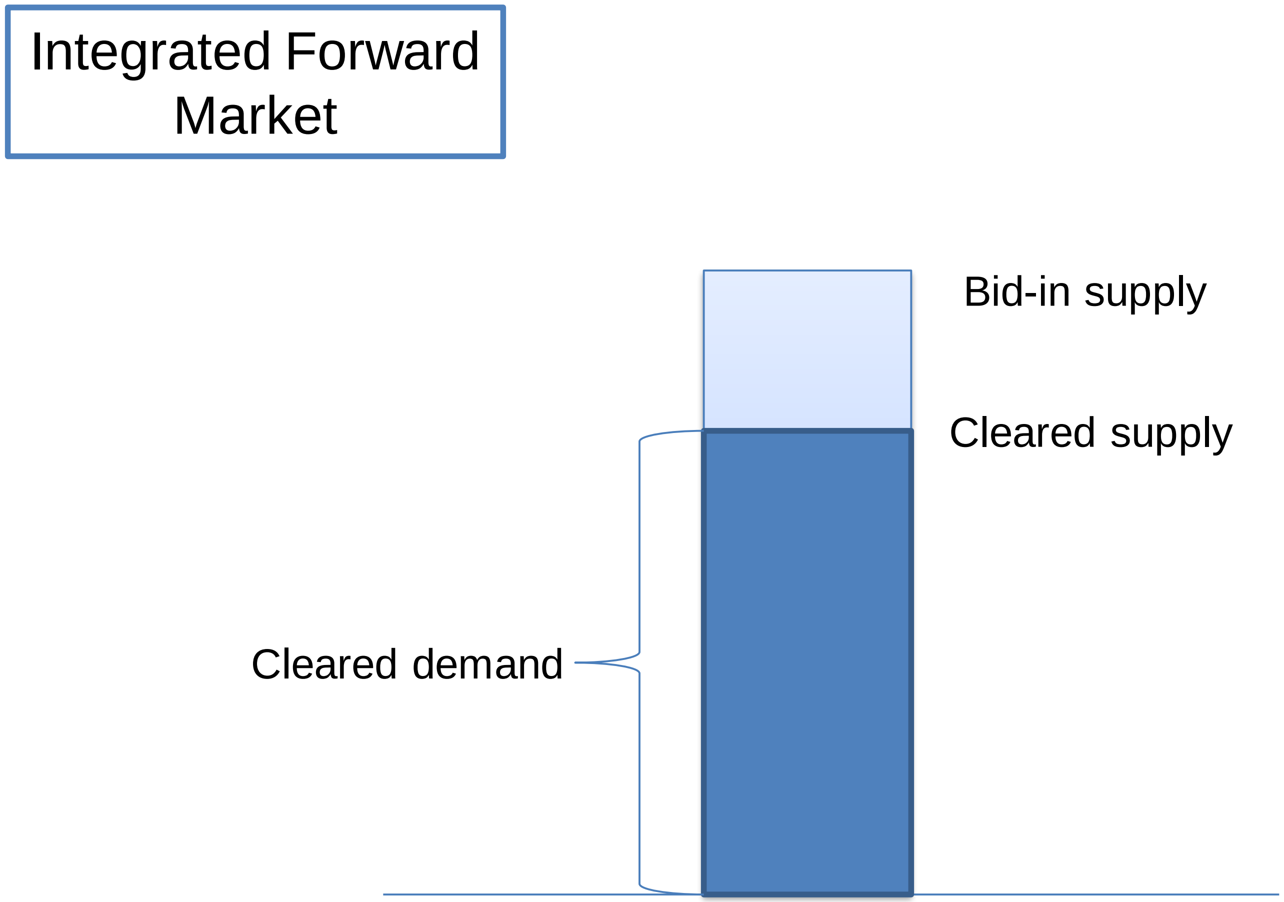
Overview of existing market structure and proposed market structures

- **Status Quo**
  - Integrated forward market co-optimizes bid-in demand and ancillary services
  - Residual unit commitment commits additional resources if IFM physical clears below ISO day-ahead net load forecast
  - Exceptional dispatch if IFM and RUC clears inconsistent operational needs
- **Option 1 – Financial**
  - Co-optimizes bid-in demand, ancillary services and imbalance reserves
  - Imbalance reserves cover historical uncertainty between IFM cleared net load and FMM net load (includes what is currently committed through RUC)
  - Exceptional dispatch if IFM clears inconsistent with operational needs
- **Option 2 – Financial + Forecast**
  - Co-optimizes bid-in demand, ISO reliability capacity, ancillary services and imbalance reserves
  - Imbalance reserves cover historical uncertainty between ISO's day-ahead net load forecast and FMM net load
  - Reliability capacity covers differences between ISO net load and cleared net load
  - Exceptional dispatch if IFM/RUC clears inconsistent with operational needs

Status-Quo is the sequential procurement of products

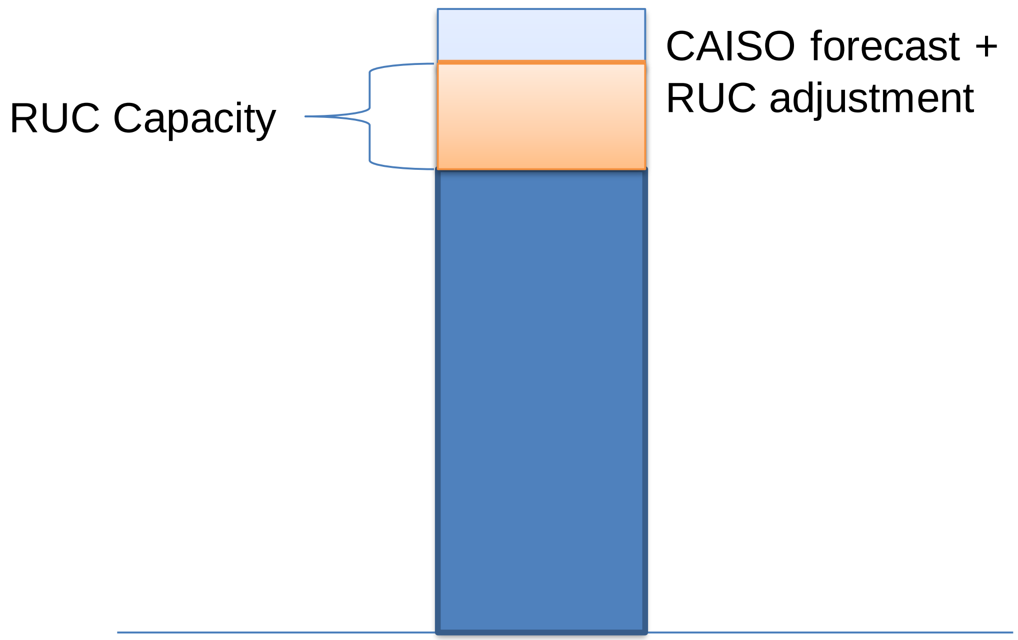
- **Integrated Forward Market:** Commit supply based on bid-in demand, and procure ancillary services
  - Allows load serving entities to take a day-ahead financial position to serve load
  - Allows generators (including VERs) to take a day-ahead financial position to generate
- **Residual Unit Commitment:** Commit additional capacity using RUC availability bids to meet CAISO forecast
- **Exceptional Dispatch:** Opportunity for operators to commit/schedule additional energy if needed for reliability purposes

Status-Quo is the sequential procurement of products

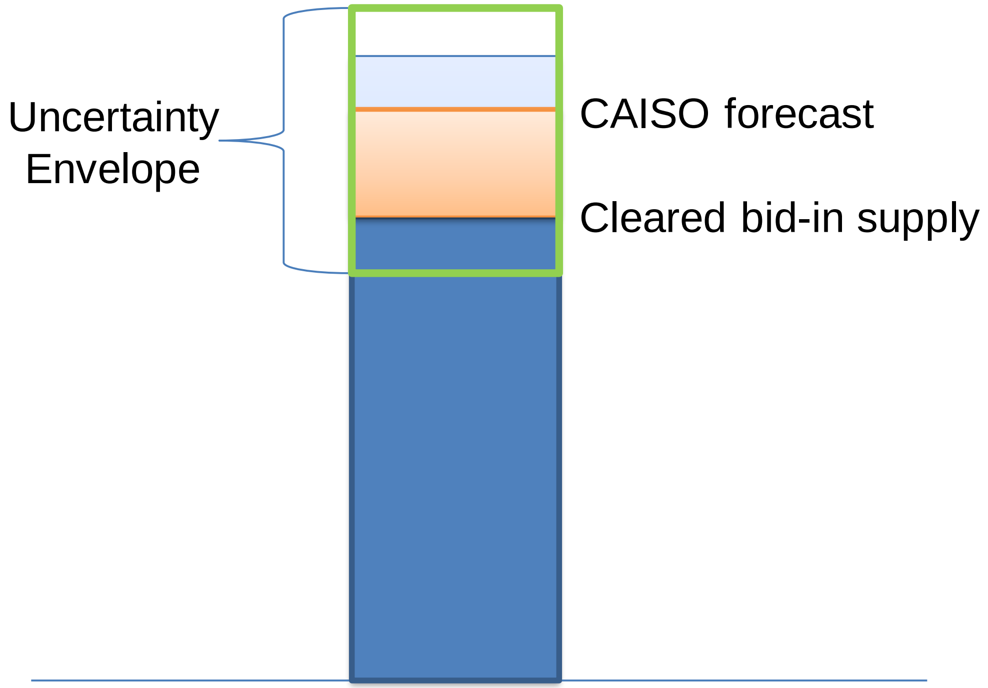


Status-Quo is the sequential procurement of products

Residual Unit Commitment

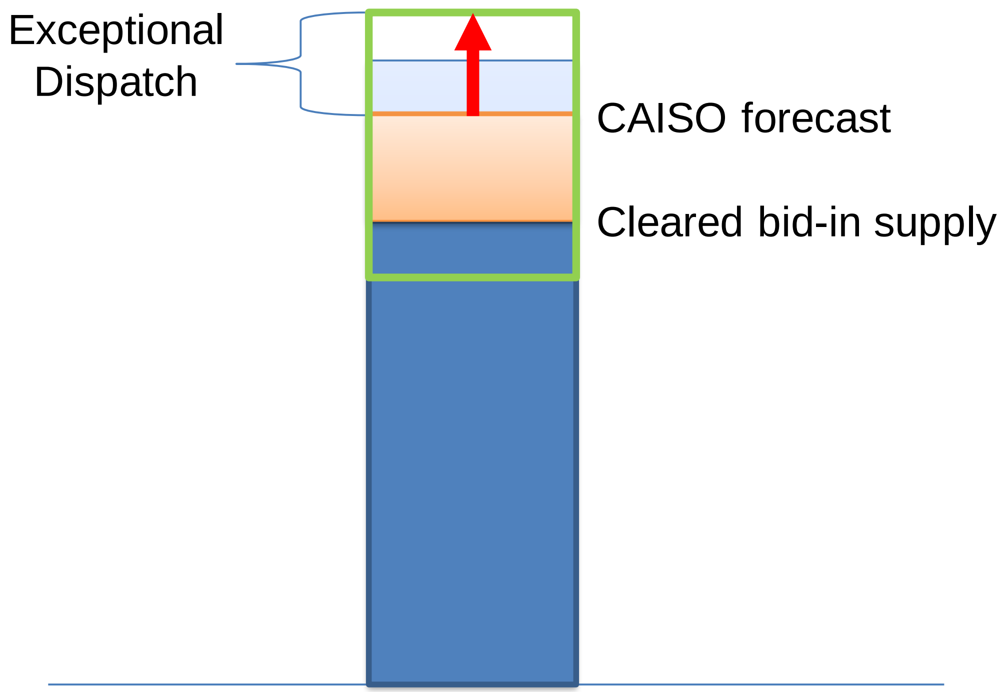


Status-Quo does not ensure uncertainty envelope can be met



Status-Quo may require use of exceptional dispatch to meet the upper bound of the uncertainty envelope

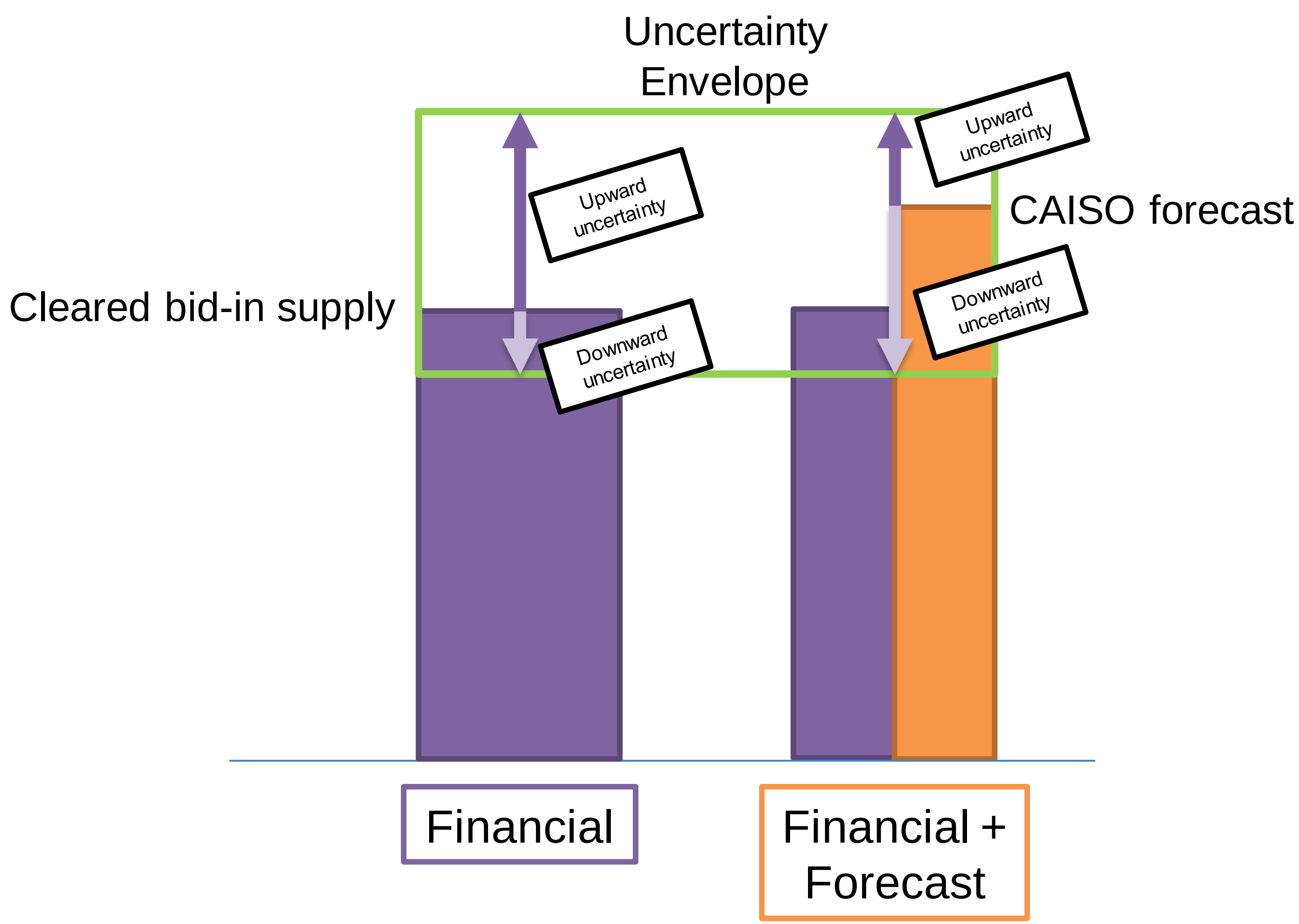
Exceptional Dispatch



Both proposed options are improvements on sequential status-quo

- Co-optimization of energy and capacity products results in market efficiencies and appropriate compensation for flexibility
- Imbalance reserves procured to address operational needs (eliminates need for sequential RUC process)
- New day-ahead market design will reduce need for out-of-market actions such as load adjustments and exceptional dispatch

Amount of upward uncertainty and downward uncertainty is dependent on the day-ahead market formulation



Comparison of Day-Ahead Market options

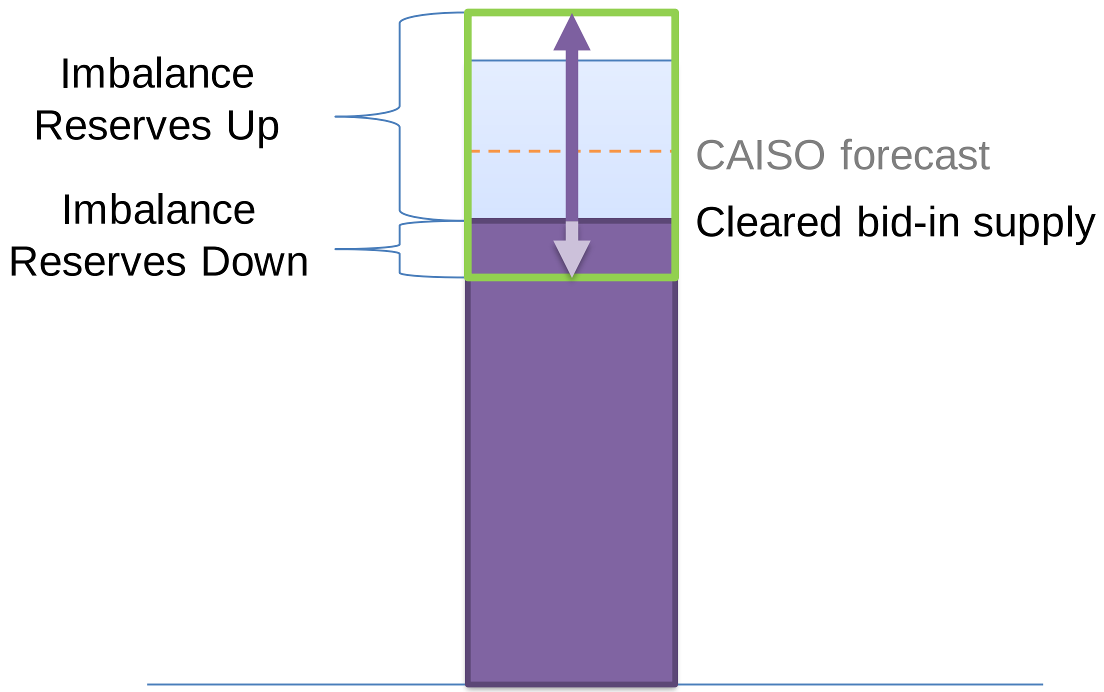
Financial

- Single co-optimized market run
- Imbalance reserves procured relative to cleared bid-in demand
  - 15-minute product
  - Does not ensure deliverability
- Same LMP for physical and virtual supply
- VER schedule is determined by bids

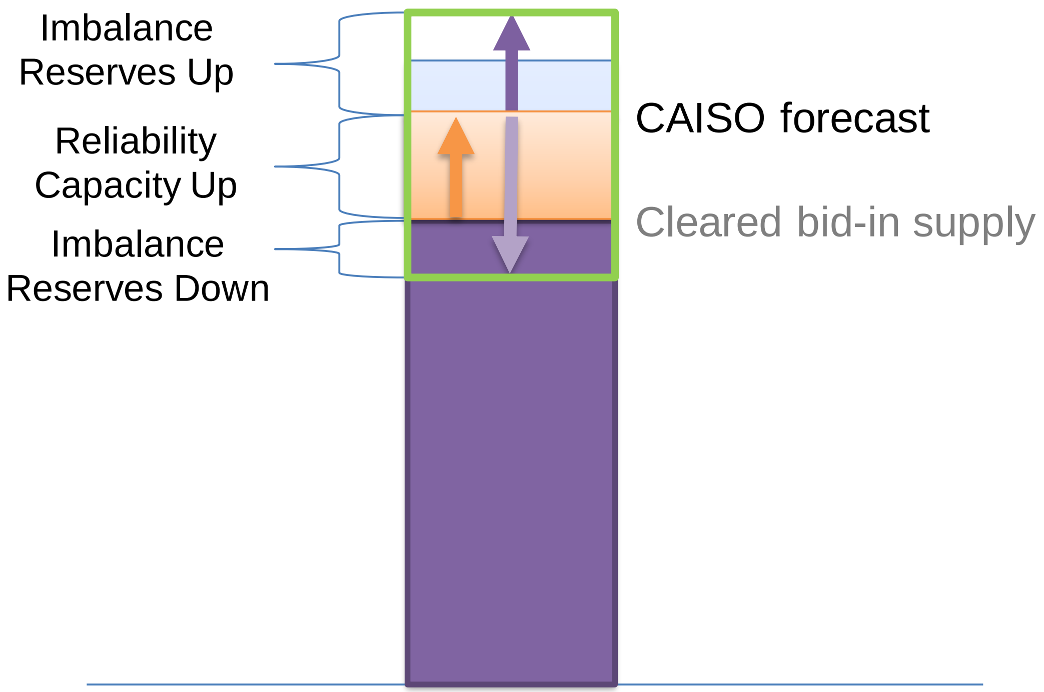
Financial + Forecast

- Single co-optimized market run
- Imbalance reserves procured relative to cleared bid-in demand
  - 15-minute product
  - Does not ensure deliverability
- Reliability capacity procured relative to CAISO forecast
  - Hourly product
  - Ensures deliverability
- Different LMP for physical and virtual supply
- VER reliability capacity is determined by VER forecast

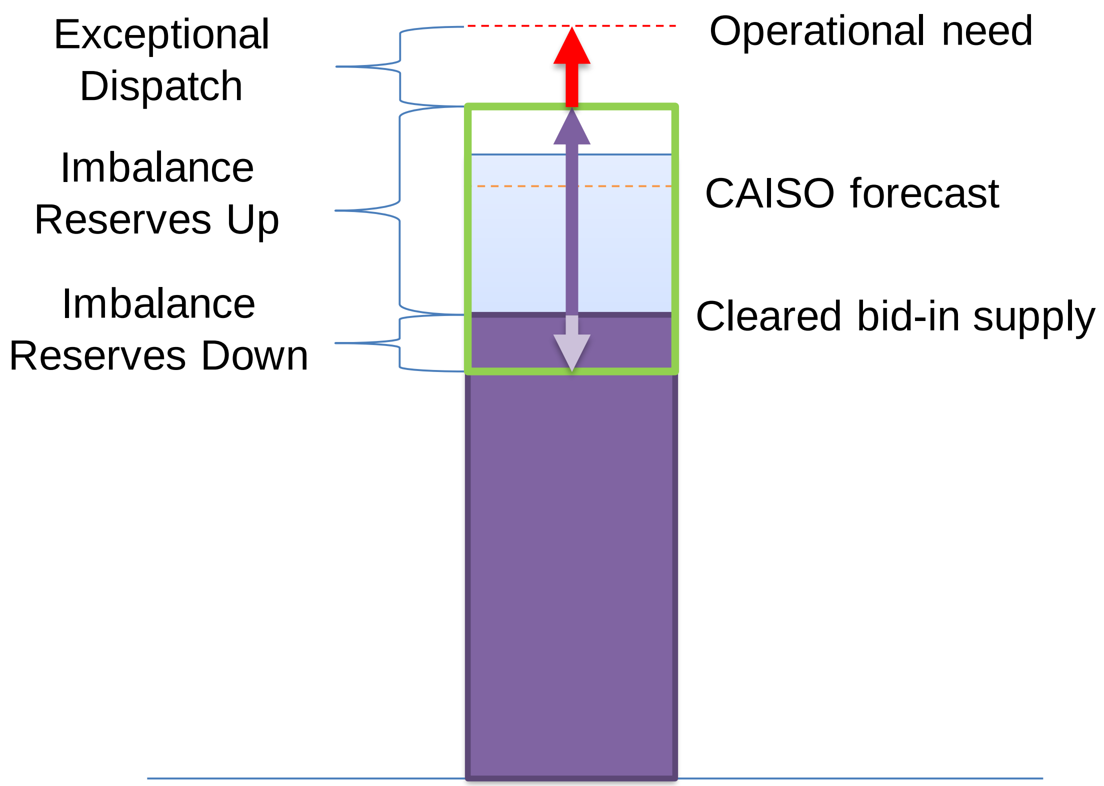
Financial Option will co-optimize energy, AS, and imbalance reserves based on cleared bid-in supply



Financial + Forecast Option will co-optimize energy, AS, and imbalance reserves based on bid-in supply and CAISO forecast



BOTH Options will include an after-market reliability assessment to meet 15-minute ramping needs and unexpected operational needs



After-market exceptional dispatch will be needed to meet extreme system conditions

Day-Ahead Market Enhancements

DATA ANALYSIS

Bridget Clark
Market Design Policy

Analysis shows uncertainty between the day-ahead and real-time market exists and is predictable

- Net load uncertainty has increased over time
- Uncertainty varies seasonally and by hour
- We can identify factors that drive uncertainty, therefore it can be addressed through a market product
  - Load, VERs, seasonality, hour, and temperature
- Procurement target can be scaled to ensure appropriate amount of imbalance reserves on an hourly basis

Performed statistical analysis to better understand historical uncertainty and trends

1. Compared correlation between net loads from each market run
   – Is net load from the market or net load from the forecast closer to net load in real?

2. Compared historical uncertainty between various market runs
   – What's the magnitude of uncertainty, and has it changed over time?

3. Identified statistically significant variables using quantile regression testing
   – What factors impact the amount of uncertainty that materializes?

Definition of net loads used in statistical analysis

- **Market Cleared Net Load** = Cleared Demand - Cleared Net Virtual Supply - Cleared VER Supply
- **Net Load Forecast** = Demand Forecast - VER Forecast
- **Adjusted Net Load Forecast** = Net Load Forecast + Operator adjustment
- **FMM Net Load** = FMM Demand Forecast - FMM VER Forecast

Analysis yields a strong correlation between net loads from each market run

	Market Cleared Net Load	Net Load Forecast	Adjusted Net Load Forecast	FMM Net Load
Market Cleared Net Load	1.0000			
Net Load Forecast	0.9485	1.0000		
Adjusted Net Load Forecast	0.9463	0.9953	1.0000	
FMM Net Load	0.9458	0.9738	0.9666	1.0000

Net Load Forecast is more strongly correlated with FMM Net Load than the Market Cleared Net Load or the Adjusted Net Load Forecast

Net load uncertainty is measured in relation from the day-ahead market runs to the fifteen-minute market

- **Uncertainty Down**: Negative values indicate the Day-Ahead Market cleared higher than the Fifteen Minute Market
  - Need for imbalance reserves down

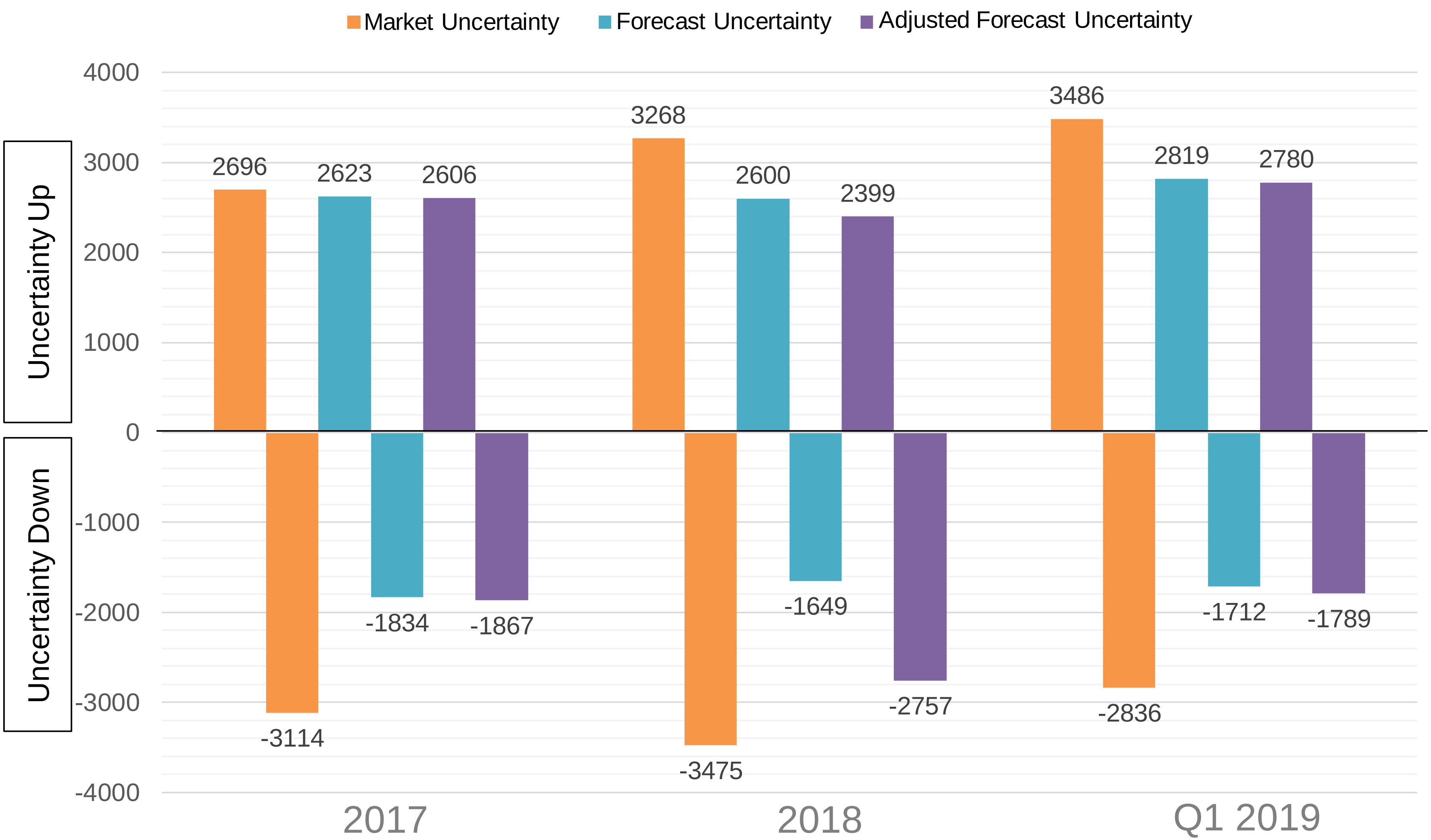
- **Uncertainty Up:** Positive values indicate the Day-Ahead Market cleared lower than the Fifteen-Minute Market
  - Need for imbalance reserves up

Amount of uncertainty that materialized between day ahead markets and real time is weakly correlated

	Market Uncertainty	Forecast Uncertainty	Adjusted Forecast Uncertainty
Market Uncertainty	1.0000		
Forecast Uncertainty	0.3974	1.000	
Adjusted Forecast Uncertainty	0.3884	0.9215	1.000

Even though day ahead net loads were correlated across market runs, the amount of uncertainty produced in real time will be different

Annual trends in uncertainty



Note: Uncertainty Up is measured at the 97.5% percentile, Uncertainty Down is measured at the 2.5% percentile.
Data set encompasses January 2017 – March 2019.

Uncertainty between markets in 2017

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
Percentiles			
99.0%	3228	3310	2341
97.5%	2696	2623	2606
95.0%	2274	2208	1498
90.0%	1798	1691	1088
75.0%	1060	923	480
50.0%	208	192	192
25.0%	-806	-461	-480
10.0%	-1815	-1067	-1088
5.0%	-2522	-1475	-1498
2.5%	-3114	-1834	-1867
1.0%	-3783	-2300	-2341

Market cleared net load produced largest amount of uncertainty at P95

Uncertainty between markets in 2018

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
Percentiles			
99.0%	4082	3187	2959
97.5%	3268	2600	2399
95.0%	2648	2096	1914
90.0%	2095	1606	1429
75.0%	1239	879	720
50.0%	274	232	71
25.0%	-794	-364	-625
10.0%	-1953	-930	-1473
5.0%	-2756	-1295	-2169
2.5%	-3475	-1649	-2757
1.0%	-4359	-2090	-3397

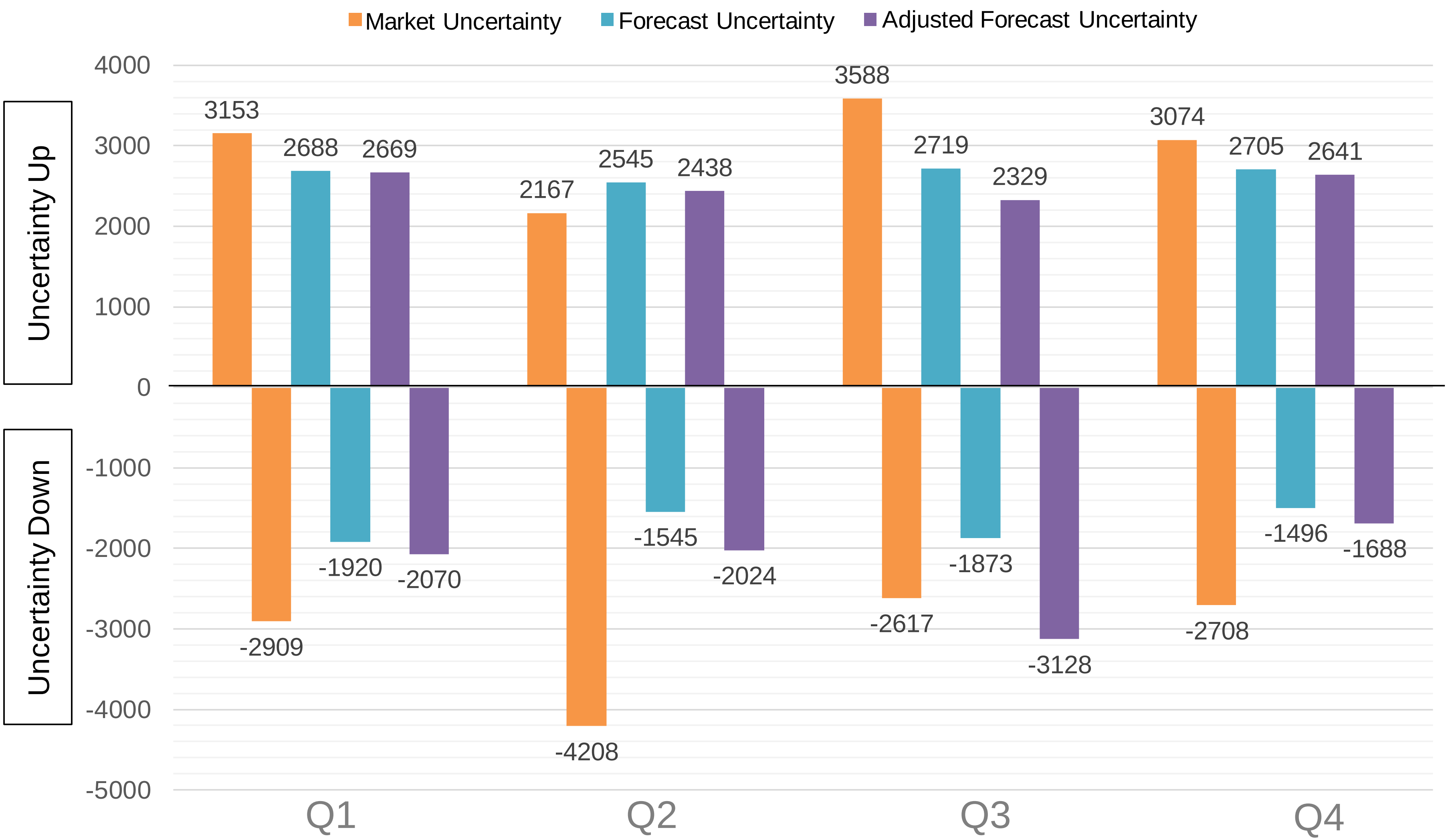
Market cleared net load produced largest amount of uncertainty at P95

Uncertainty between markets in Q1 2019

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
Percentiles			
99.0%	4273	3619	3604
97.5%	3486	2819	2780
95.0%	2988	2270	2234
90.0%	2414	1719	1684
75.0%	1574	892	850
50.0%	696	219	180
25.0%	-299	-357	-409
10.0%	-1448	-934	-1003
5.0%	-2214	-1346	-1432
2.5%	-2836	-1712	-1789
1.0%	-3558	-2103	-2203

Market cleared net load produced largest amount of uncertainty at P95

Amount of historical uncertainty varies seasonally



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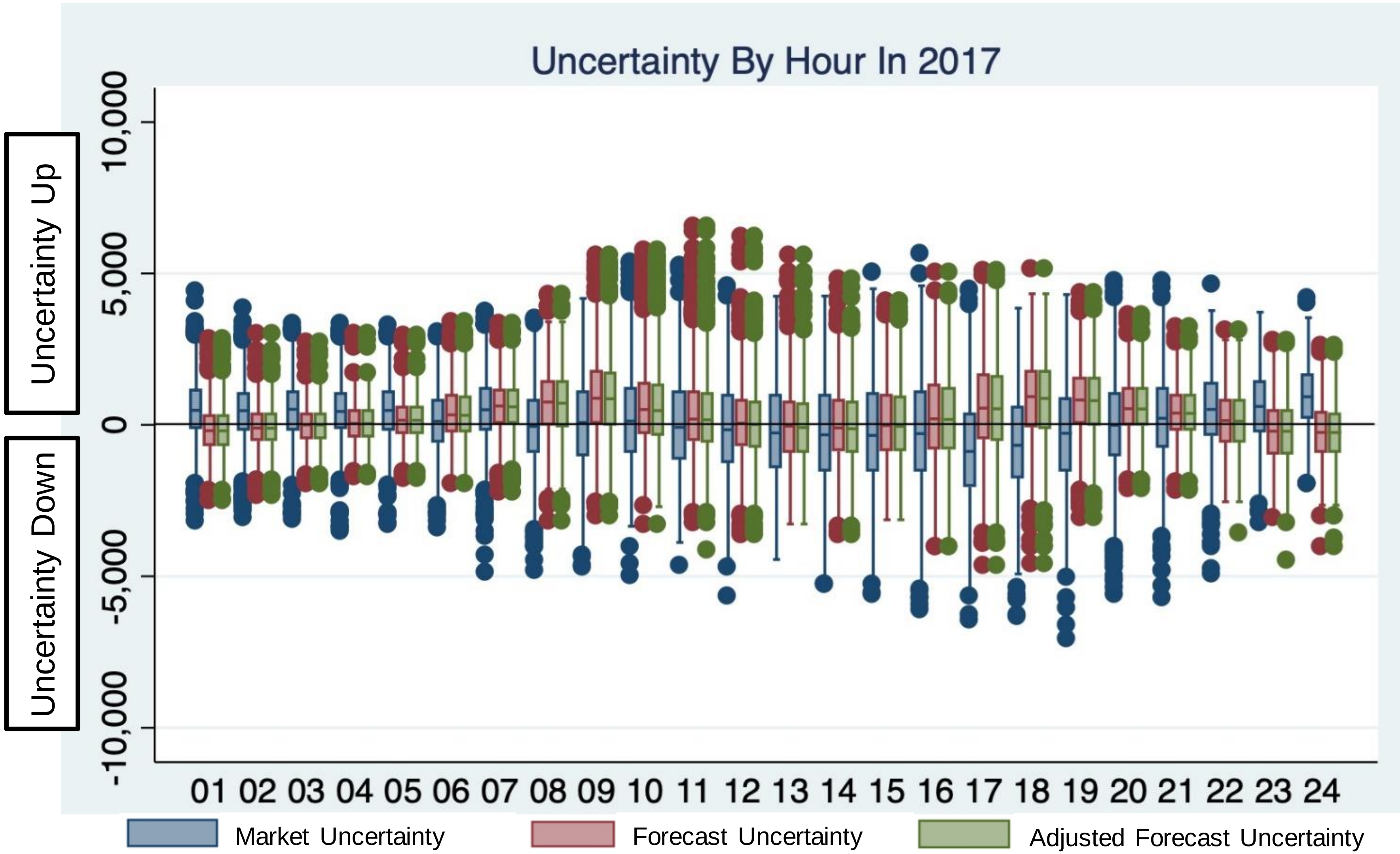
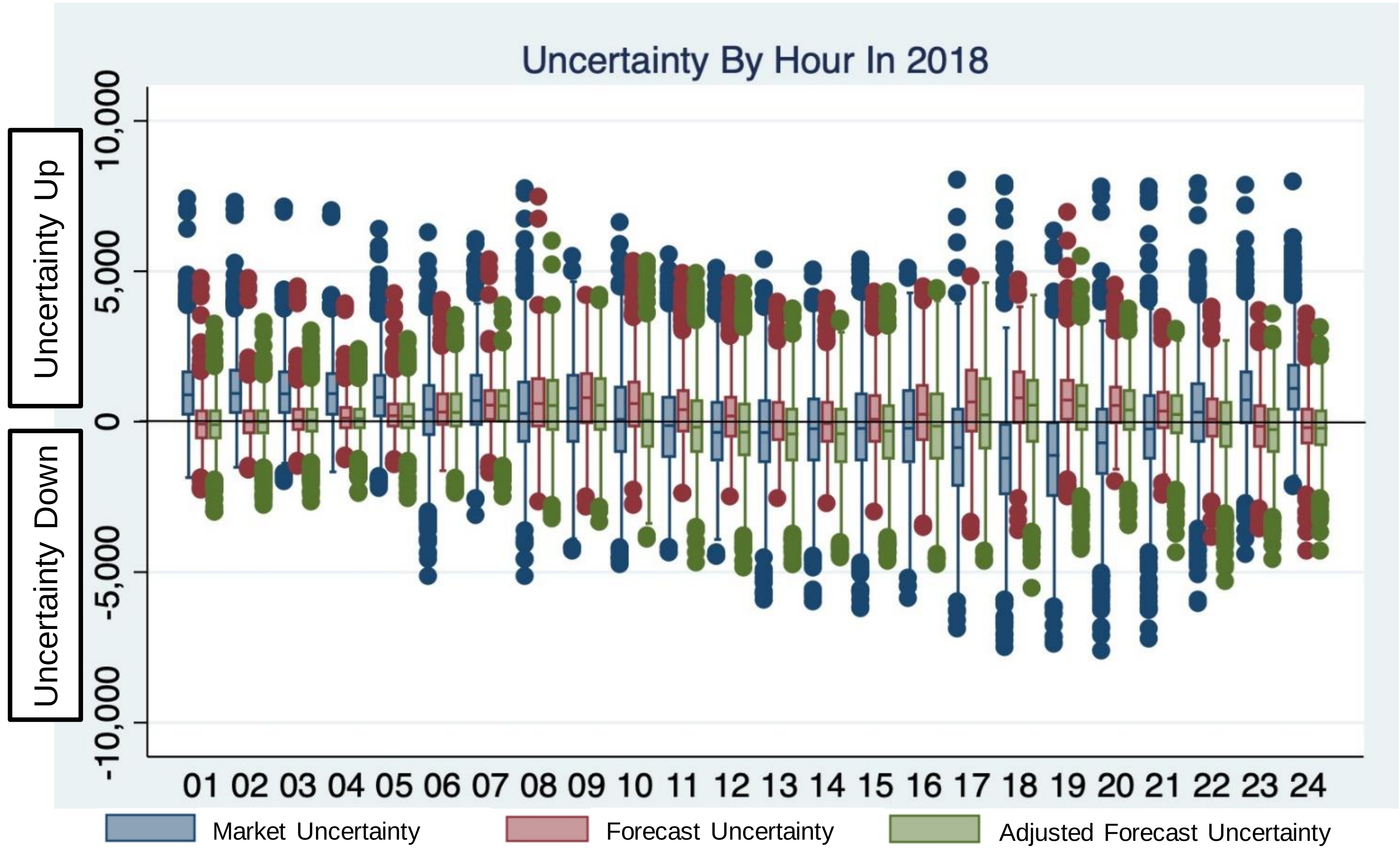
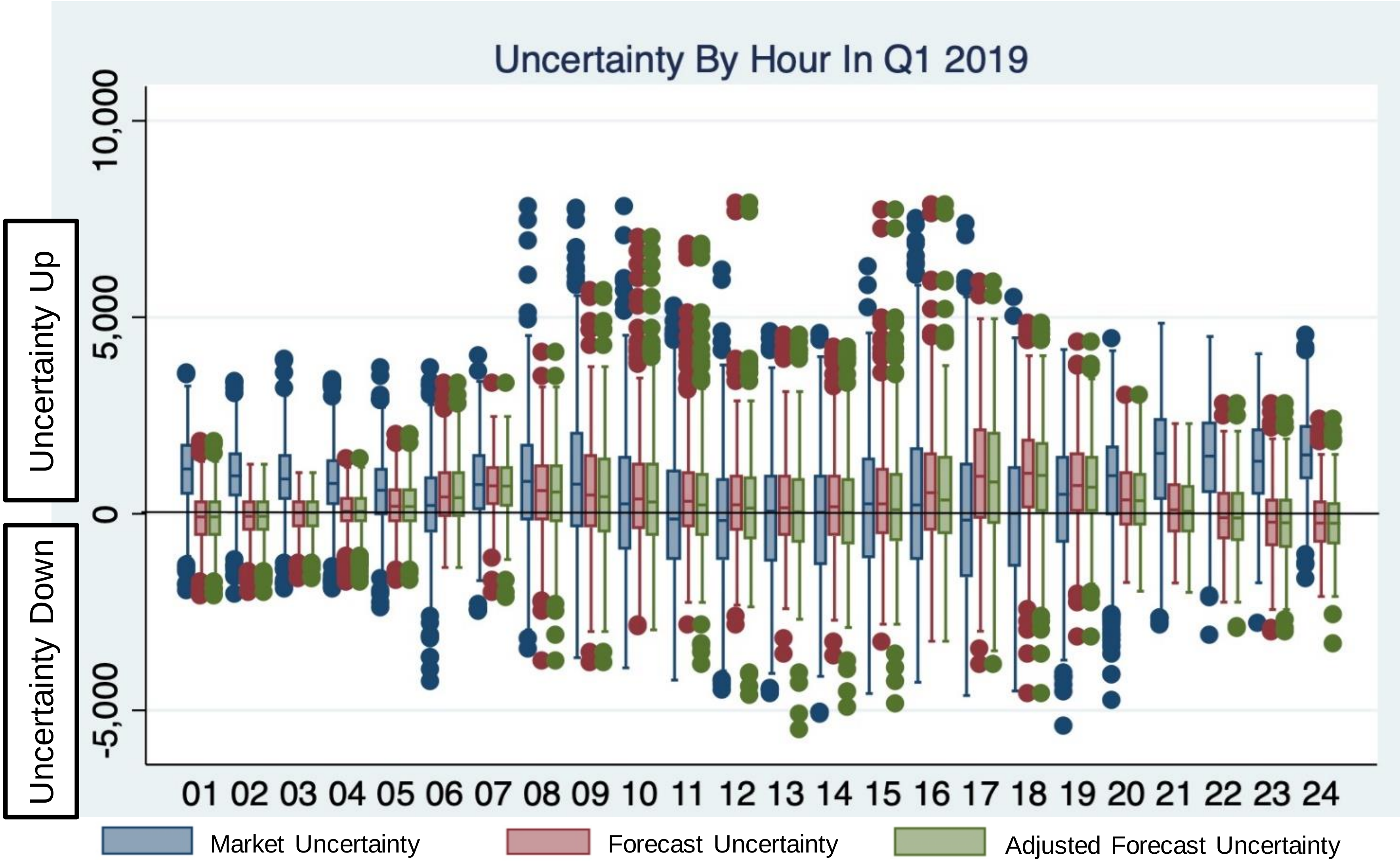
Net load uncertainty by hour in 2017



Uncertainty by hour in 2018



Uncertainty by hour in Q1 2019



Statistical analysis supports theoretical prediction that uncertainty can be predicted

- Given the observed patterns, we tested to confirm the patterns were not random and were actually related to year, season, and hour

- The results of the testing confirm we can procure the appropriate amount of imbalance reserves based on identified factors

Quantile regression testing identified the following variables have statistical significance on uncertainty

Variable Name	Description	Unit
Cleared Load	Total MW that cleared the IFM/RUC/RUC Net Short	MW per Hour
VERs Forecast	MW of VERs forecasted	MW per Hour
San Jose Temp	Hourly temperature reported by the San Jose weather station	Degrees Fahrenheit
Fresno Temp	Hourly temperature reported by the Fresno weather station	Degrees Fahrenheit
LA Temp	Hourly temperature reported by the Downtown LA weather station	Degrees Fahrenheit
Hour	Operating Hour	Hour (1-24)

Day-Ahead Market Enhancements

COMPARISON OF DAY-AHEAD MARKET OPTIONS

Don Tretheway
Sr. Advisor
Market Design Policy

Overview of existing market structure and proposed market structures

- **Status Quo**
  - Integrated forward market co-optimizes bid-in demand and ancillary services
  - Residual unit commitment commits additional resources if IFM physical clears below ISO day-ahead net load forecast
  - Exceptional dispatch if IFM and RUC clears inconsistent operational needs
- **Option 1 – Financial**
  - Co-optimizes bid-in demand, ancillary services and imbalance reserves
  - Imbalance reserves cover historical uncertainty between IFM cleared net load and FMM net load
  - Exceptional dispatch if IFM clears inconsistent with operational needs
- **Option 2 – Financial + Forecast**
  - Co-optimizes bid-in demand, ISO reliability capacity, ancillary services and imbalance reserves
  - Imbalance reserves cover historical uncertainty between ISO's day-ahead net load forecast and FMM net load
  - Reliability capacity covers differences between ISO net load and cleared net load
  - Exceptional dispatch if IFM/RUC clears inconsistent with operational needs

Option 1 - Financial Constraints

$$\sum_{i} EN_{i,t} + \sum_{j} EN_{j,t} = \sum_{i} L_{i,t} + \sum_{j} L_{j,t} + Loss_{t} \quad \lambda_{t}$$

$$\sum_{i} IRU_{i,t} \geq IRUR_{t} \quad \rho_{t}$$

$$\sum_{i} IRD_{i,t} \geq IRDR_{t} \quad \sigma_{t}$$

Option 2 – Financial + Forecast Constraints

$$\sum_i EN_{i,t} + \sum_j EN_{j,t} = \sum_i L_{i,t} + \sum_j L_{j,t} + Loss_t \qquad \lambda_t$$

$$\sum_i REN_{i,t} = \sum_i \left(EN_{i,t} + RCU_{i,t} - RCD_{i,t}\right) = D_t \qquad \xi_t$$

$$\sum_i IRU_{i,t} \geq IRUR_t \qquad \rho_t$$

$$\sum_i IRD_{i,t} \geq IRDR_t \qquad \sigma_t$$

Objective Function for Financial vs. Financial + Forecast

- Unit Commitment costs
  - Start-Up, Minimum Load, State Transition costs
- Incremental energy costs for Energy schedules
- Ancillary services costs at AS bids
- Imbalance reserves Up/Down costs at IR bids
  - $\sum_t \sum_i \left(IRU_{i,t}\, IRUP_{i,t} + IRD_{i,t}\, IRDP_{i,t} \right)$
- Reliability Capacity Up/Down costs at IR bids
  - $\sum_t \sum_i \left(RCU_{i,t}\, IRUP_{i,t} + RCD_{i,t}\, IRDP_{i,t} \right)$
    $REN_{i,t} - EN_{i,t} \leq RCU_{i,t}$
    $EN_{i,t} - REN_{i,t} \leq RCD_{i,t}$

Settlement for Financial vs. Financial + Forecast

- Supply
  - $-EN_{i,t}\,\lambda_t, t = 1,2,\dots,T_D$
  - $-EN_{j,t}\,\lambda_t, t = 1,2,\dots,T_D$
- Demand
  - $+L_{i,t}\,\lambda_t, t = 1,2,\dots,T_D$
  - $+L_{j,t}\,\lambda_t, t = 1,2,\dots,T_D$
- Imbalance Reserves
  - $-IRU_{i,t}\,\rho_t, t = 1,2,\dots,T_D$
  - $-IRD_{i,t}\,\sigma_t, t = 1,2,\dots,T_D$
- Reliability Energy
  - $-REN_{i,t}\,\xi_t = -\left(EN_{i,t} + RCU_{i,t} - RCD_{i,t}\right)\xi_t, t = 1,2,\dots,T_D$
- Marginal loss over-collection (to measured demand)
- Congestion revenue (to CRRs)

Option 1 – Financial

- Pros
  - Additional unit commitment to meet upward and downward uncertainty
  - LSEs ability to secure day-ahead position based on bids maintained
  - Imbalance reserve need is driven by historical IFM net load error, not CAISO forecast error; leads to stronger cost causation
- Cons
  - Scaling requirement based upon forecasted net load is difficult given need to “forecast” cleared virtual bids, VERs, and load
  - No 100% guarantee energy and imbalance reserves will clear and cover ISO day-ahead net load forecast and uncertainty
  - Deliverability of ISO day-ahead net load forecast only as good as imbalance reserve deliverability

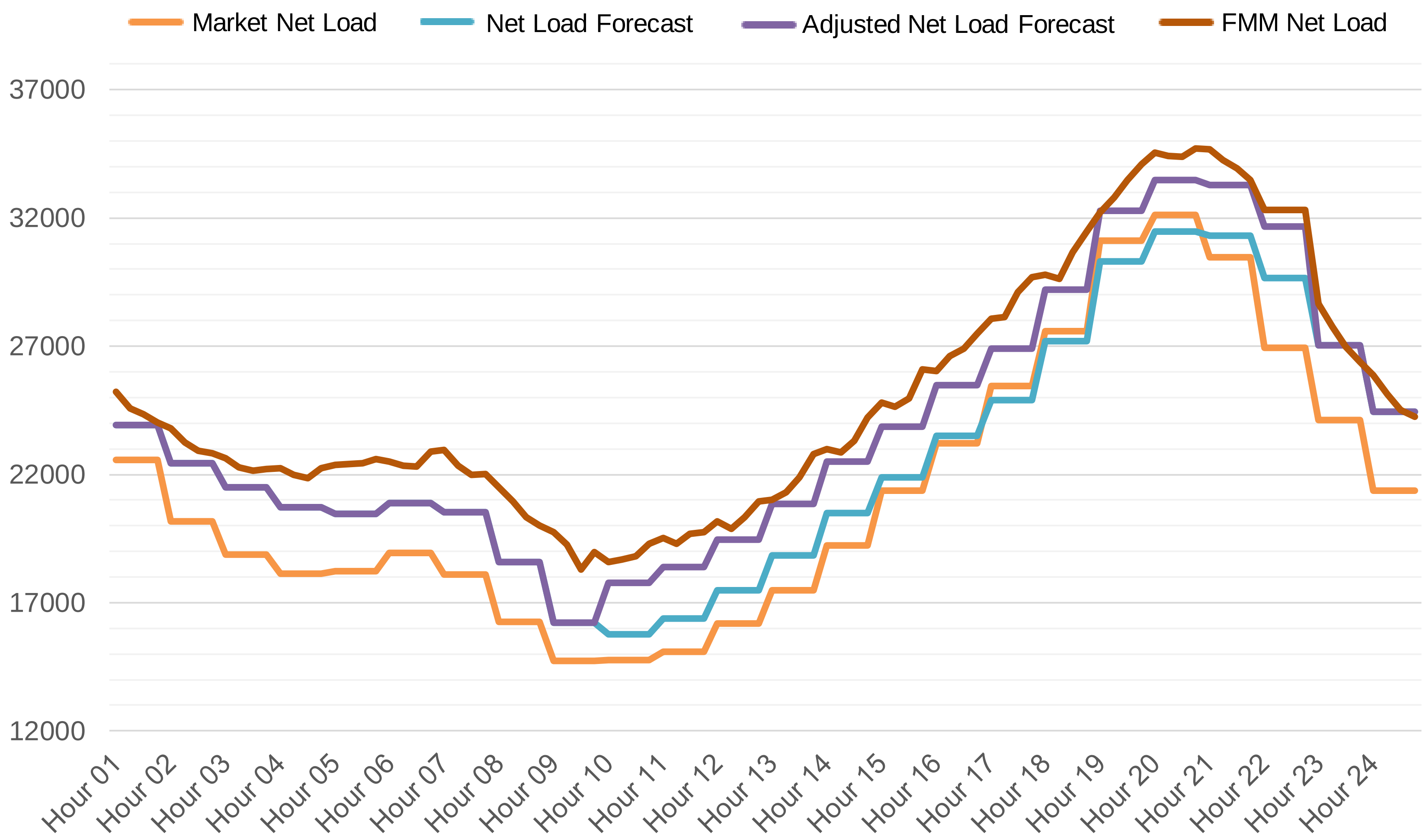
Option 2 – Financial + Forecast

- Pros
  - Additional unit commitment to meet upward and downward uncertainty
  - Difference between IFM cleared net load and CAISO net load forecast is transmission feasible
  - ISO net load forecast is used in the market clearing and therefore scaling the imbalance reserve requirement is more straight forward
  - Virtual supply and physical supply settle at different prices reflecting their reliability value

Option 2 – Financial + Forecast

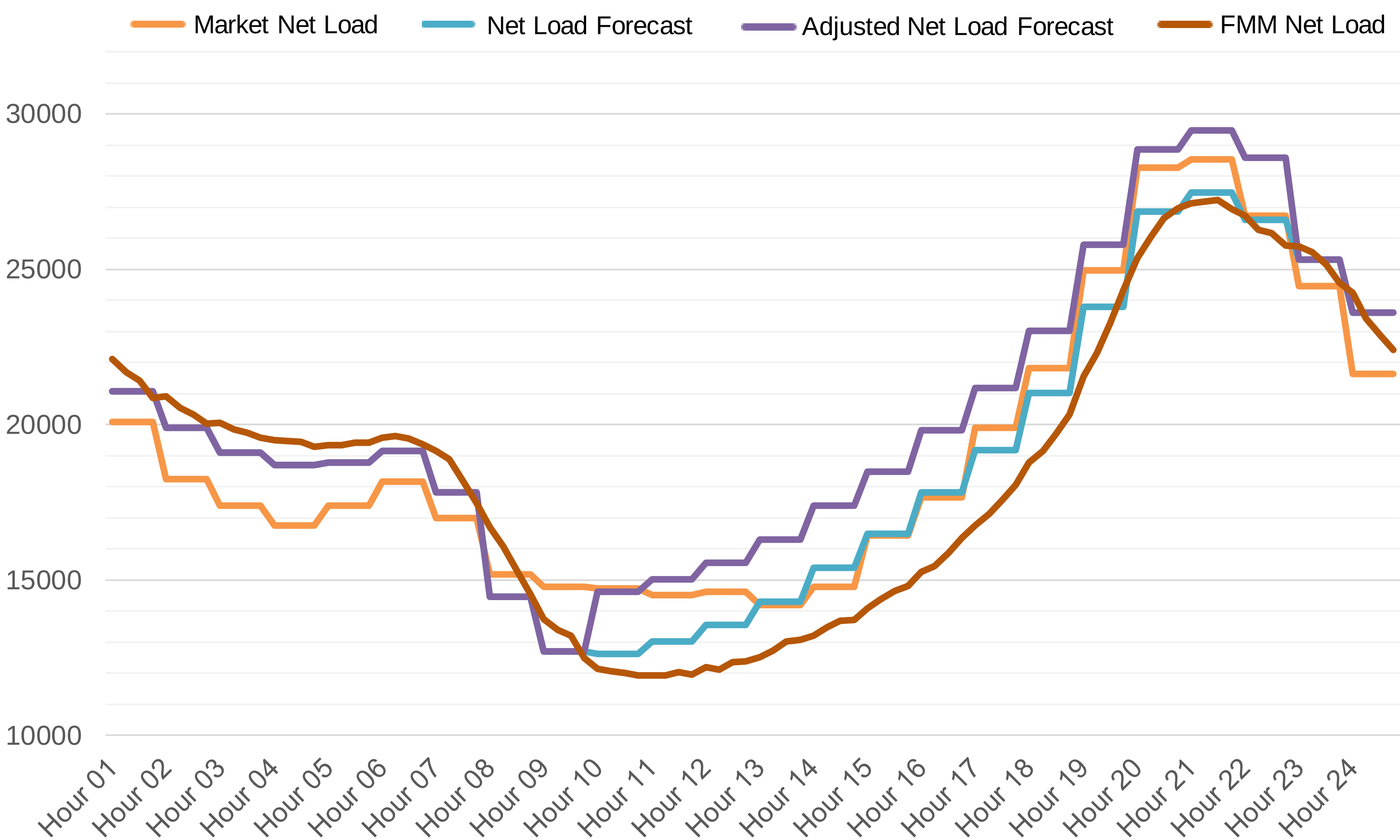
- Cons
  - ISO net load forecast has some influence in load serving entities' ability to establish their day-ahead financial position
  - Virtual supply and physical supply can settle at different prices
    - May have unintended consequences
  - VER reliability energy is based upon ISO forecast, and the difference between VER reliability energy and VER energy schedule is settled as reliability capacity
    - May have unintended consequences
  - Different prices for imbalance reserve (15 min ramp) and reliability capacity (60 min ramp) for same real-time must offer obligation (independent of locational aspect)

Case Study #1: High IFM Error – 8/12/2018



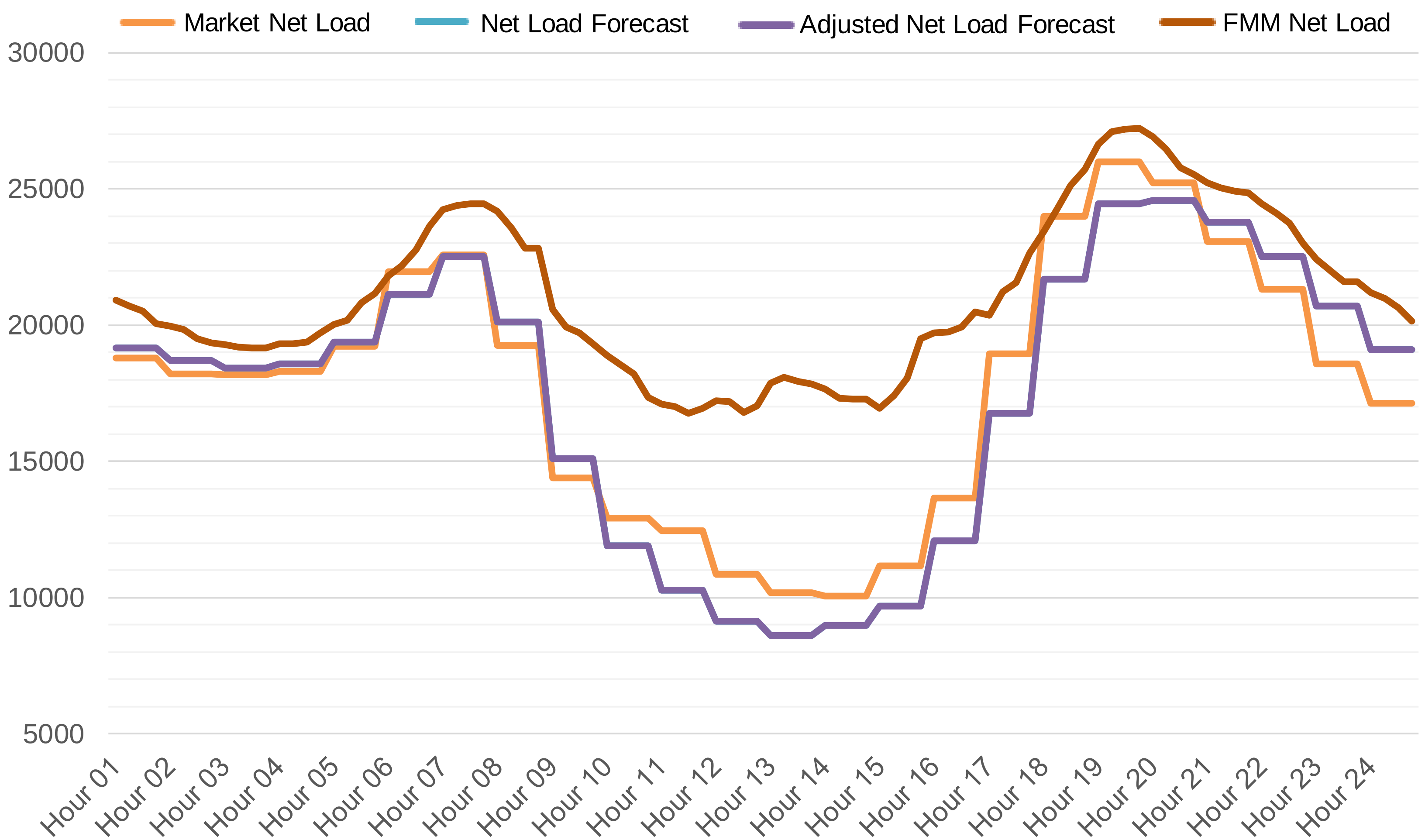
Including the CAISO's forecast in the market lead to a more efficient day-ahead unit commitment

Case Study #2: High RUC Error – 7/4/2018



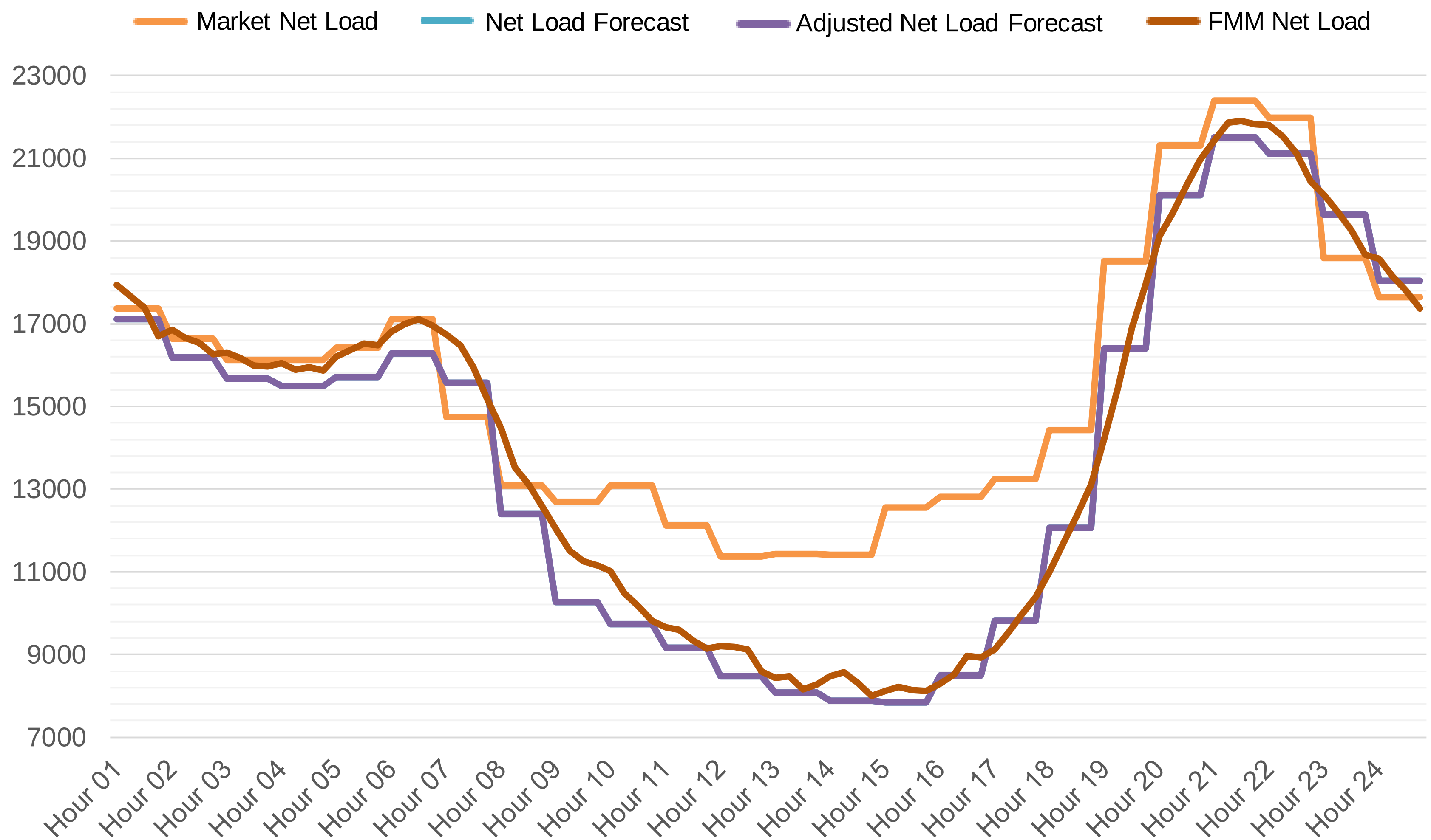
Including the CAISO's forecast + adjustment lead to over commitment of day-ahead resources

Case Study #3: Cloud Cover – 3/5/2019



If we procured to the CAISO forecast, we would have had a larger shortfall in the belly of the duck

Case Study #4: Highest % of Renewables – 5/19/2018



Market wanted to procure more physical supply than CAISO forecast

Day-Ahead Market Enhancements

NEXT STEPS

Kristina Osborne
Lead Stakeholder Engagement and Policy Specialist
Stakeholder Affairs

Next steps for Day-Ahead Market Enhancements

Item	Date
Market Surveillance Committee Meeting	Monday, August 19th
Stakeholder Comments Due*	**Tuesday, August 27th**
Straw Proposal	September/October 2019
Market Surveillance Committee Meeting	October 11, 2019
Revised Straw Proposal	November/December 2019
Draft Final Proposal	February 2020
Draft Tariff Language	Q2 & Q3 2020
BRS Development	Q2 & Q3 2020
Policy Final Proposal	Q3 2020
EIM GB & ISO BOG	Q4 2020
FERC Filing	Q1 2021
Implementation	Fall 2021

*Please submit stakeholder comments using the template on the initiative webpage to initaitivecomments@caiso.com

APPENDIX

Uncertainty across markets in Q1: January thru March

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
99.0%	3824	3402	3386
97.5%	3153	2688	2669
95.0%	2672	2188	2152
90.0%	2136	1626	1587
75.0%	1323	832	797
50.0%	444	150	117
25.0%	-545	-471	-518
10.0%	-1611	-1086	-1158
5.0%	-2300	-1516	-1617
2.5%	-2909	-1920	-2070
1.0%	-3558	-2388	-2590

Data set encompasses January 2017 – March 2019

Uncertainty across markets in Q2: April thru June

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
99.0%	2667	3139	2959
97.5%	2167	2545	2438
95.0%	1763	2067	2017
90.0%	1278	1596	1555
75.0%	502	871	841
50.0%	-471	220	182
25.0%	-1578	-416	-481
10.0%	-2764	-946	-1097
5.0%	-3494	-1262	-1553
2.5%	-4208	-1545	-2024
1.0%	-5068	-1871	-2631

Data set encompasses January 2017 – March 2019

Uncertainty across markets in Q3: July thru September

Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
99.0%	4242	3484	3125
97.5%	3588	2719	2329
95.0%	2954	2156	1806
90.0%	2354	1671	1361
75.0%	1531	946	628
50.0%	609	206	-96
25.0%	-359	-441	-871
10.0%	-1324	-1083	-1839
5.0%	-1941	-1469	-2532
2.5%	-2617	-1873	-3128
1.0%	-3371	-2265	-3679

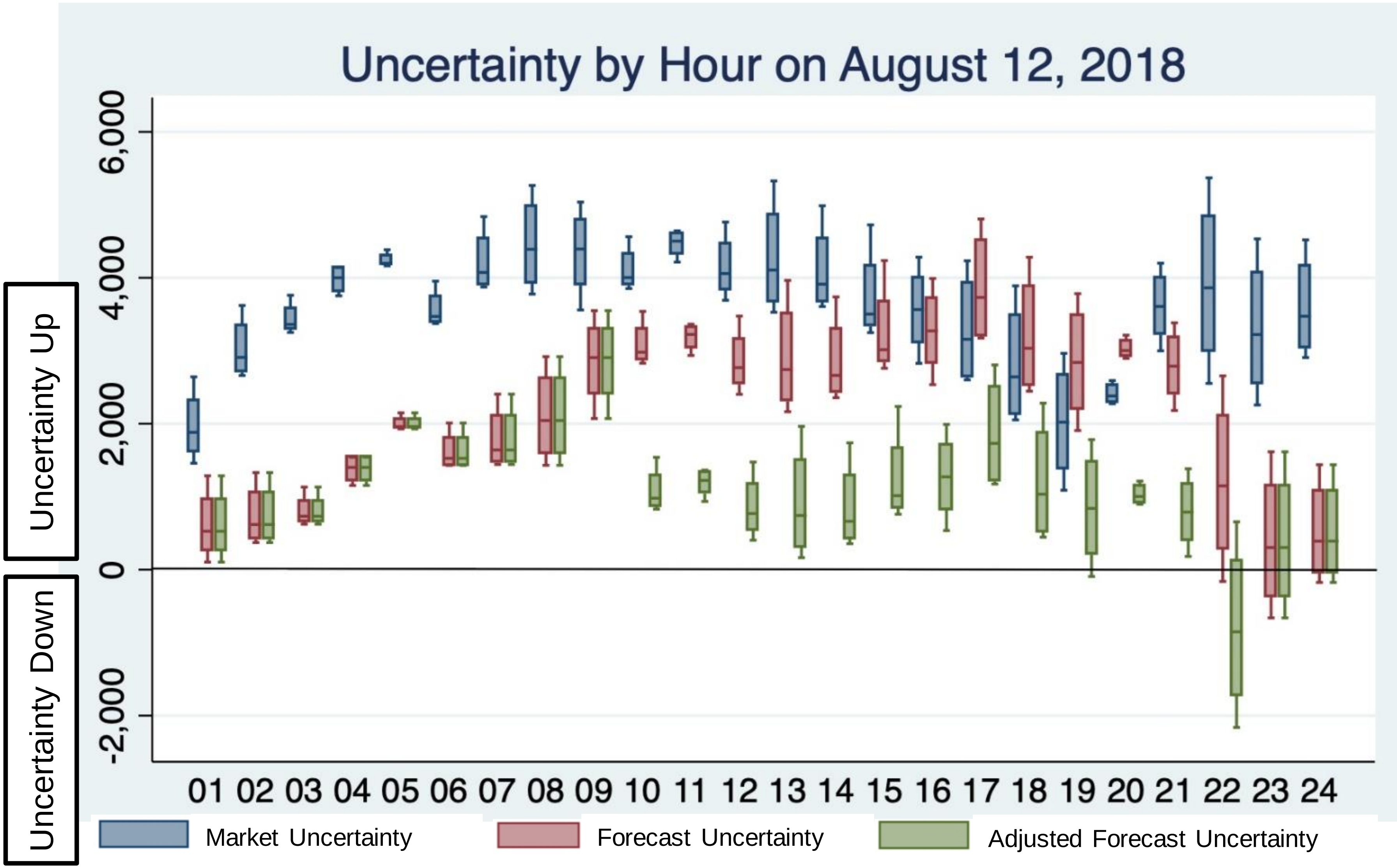
Data set encompasses January 2017 – March 2019

Uncertainty across markets in Q4: October thru December

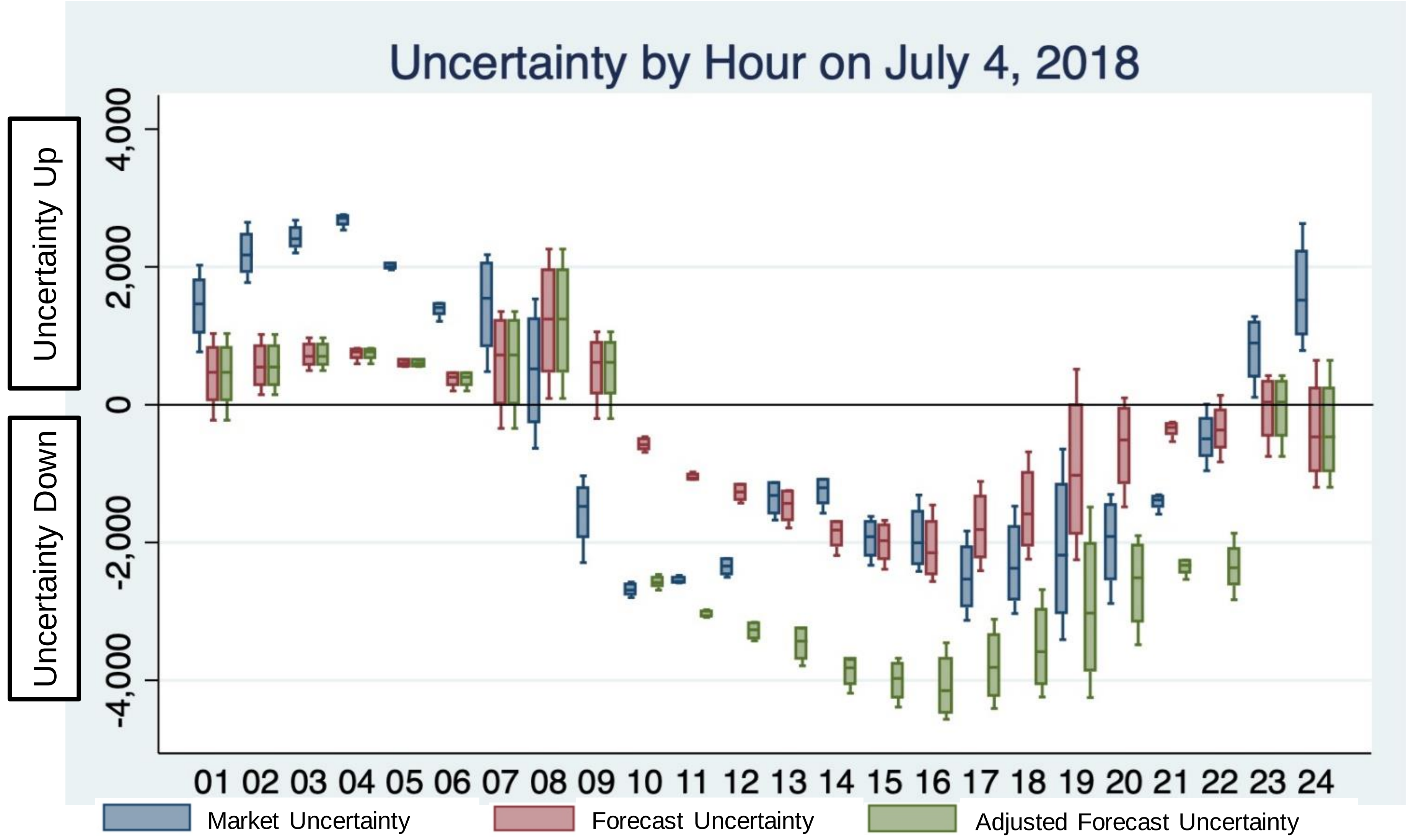
Measures	FMM to Market	FMM to Forecast	FMM to Adjusted Forecast
99.0%	3821	3234	3185
97.5%	3074	2705	2641
95.0%	2590	2259	2194
90.0%	2081	1757	1703
75.0%	1327	994	943
50.0%	534	343	307
25.0%	-411	-221	-291
10.0%	-1390	-801	-918
5.0%	-2043	-1160	-1319
2.5%	-2708	-1496	-1688
1.0%	-3448	-1856	-2160

Data set encompasses January 2017 – March 2019

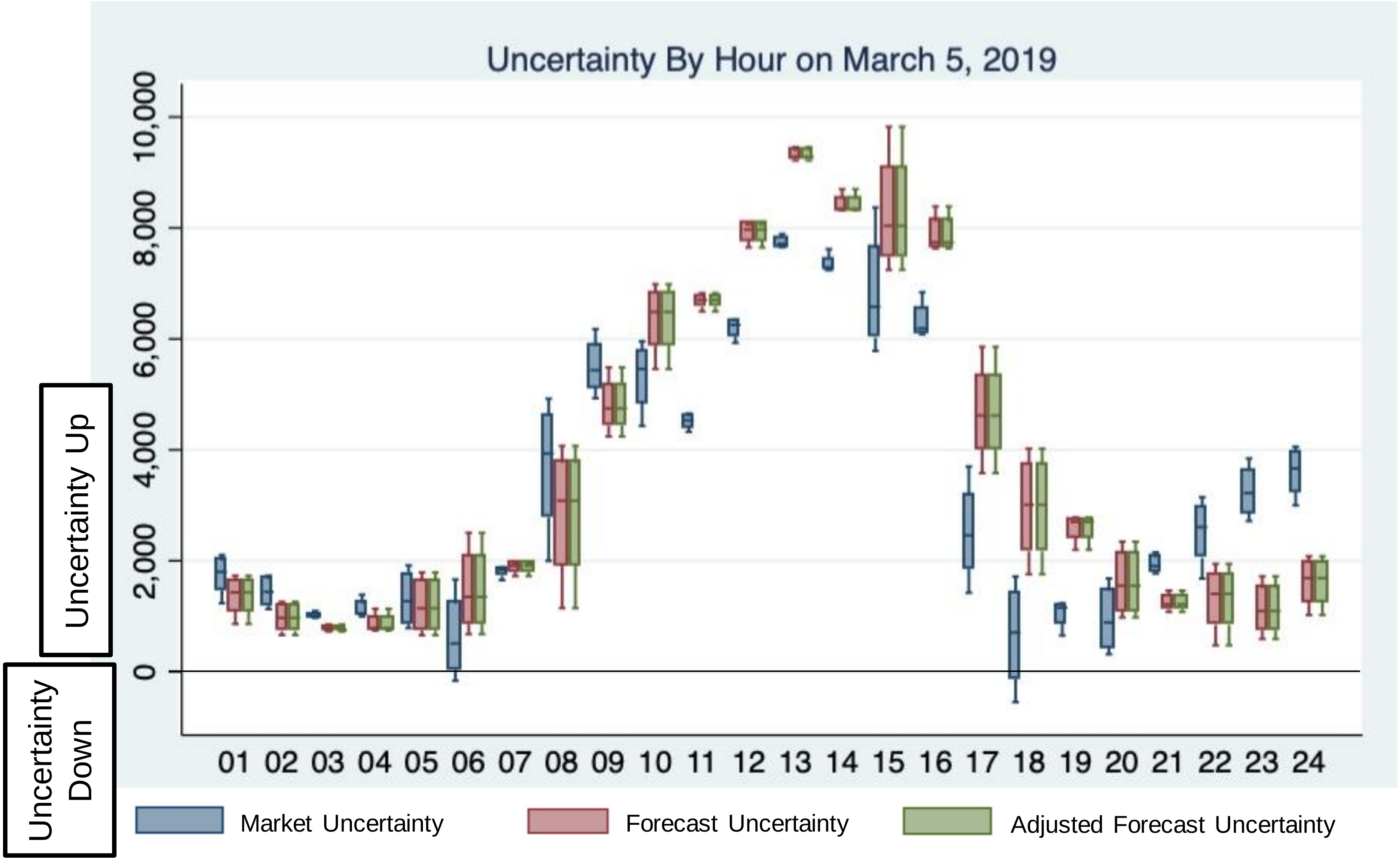
Case Study #1: High IFM Error – 8/12/2018



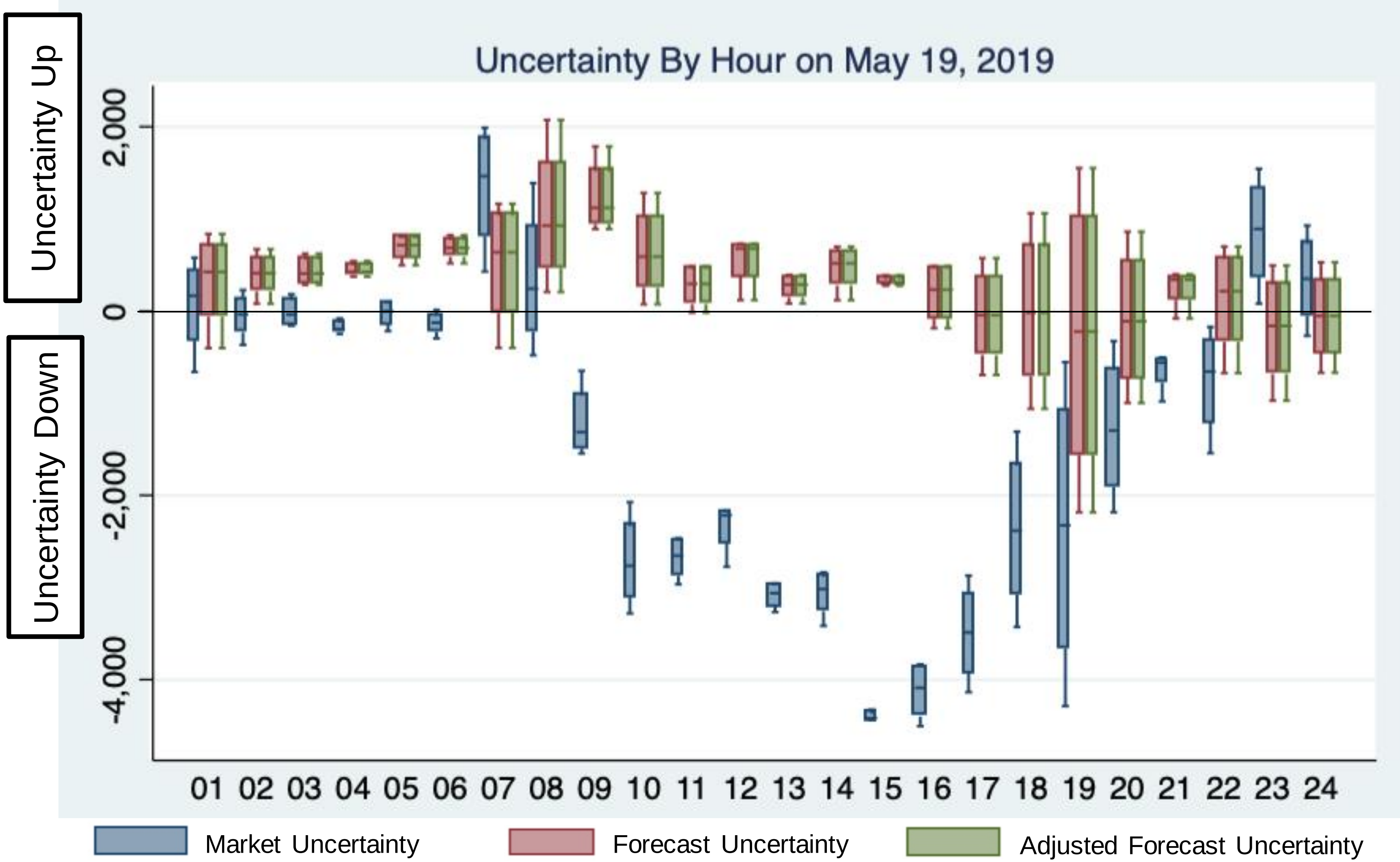
Case Study #2: High RUC Error – 7/4/2018



Case Study #3: Cloud Cover – 3/5/2019



Case Study #4: Highest % of Renewables – 5/19/2018



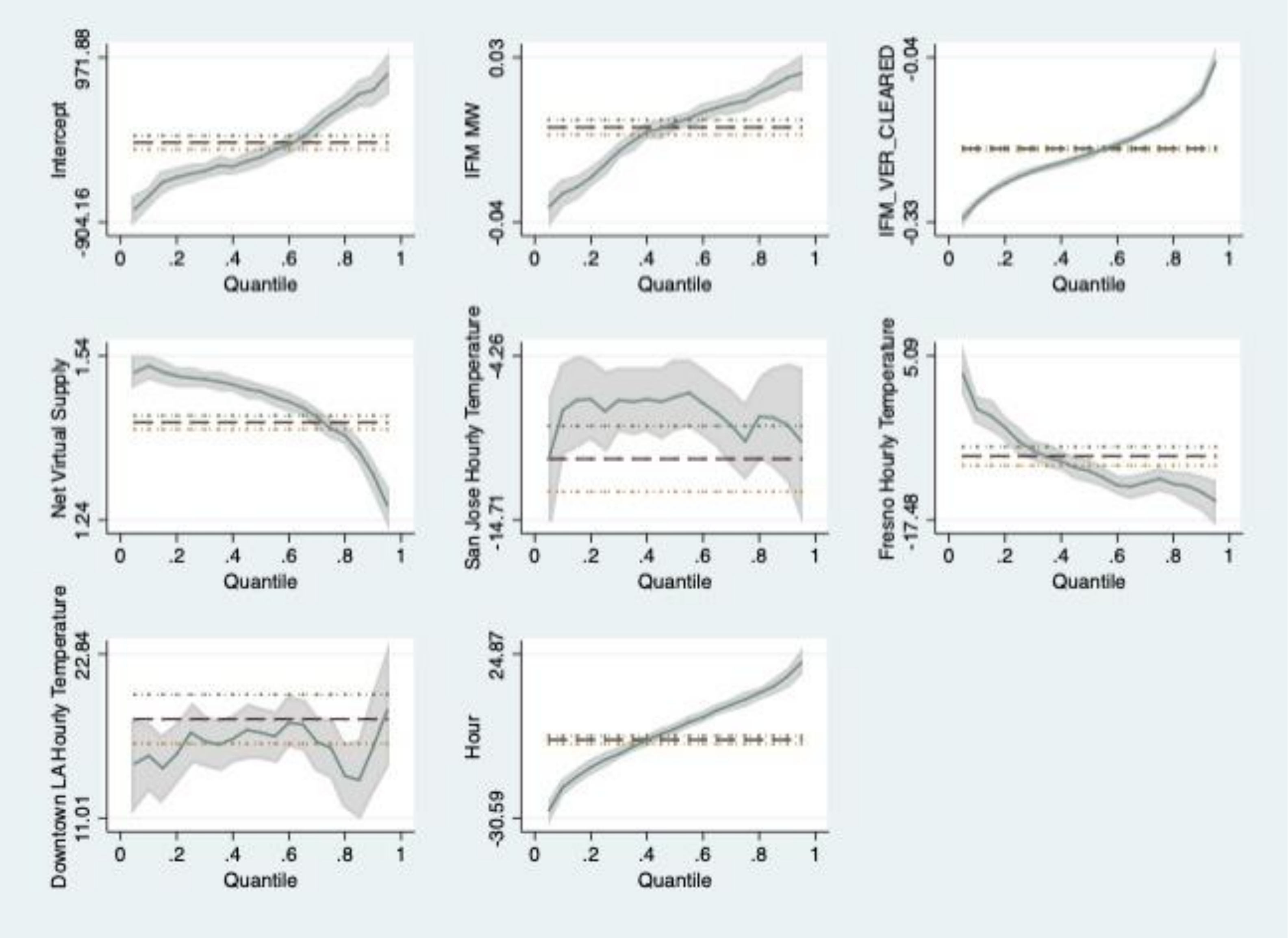
Quantile Regression Results Model 1

	OLS	Q(.05)	Q(.1)	Q(.25)
IFM MW	0.002	-0.029***+	-0.024***+	-0.013***+
VERs Cleared	-0.201***	-0.321***+	-0.295***+	-0.249***+
Net Virtuals	1.421***	1.511***+	1.522***+	1.501***+
San Jose Temp	-10.807***	-10.783***	-7.700***	-7.782***+
Fresno Temp	-8.661***	2.576	-2.201* +	-6.646***+
LA Temp	18.143***	14.929***	15.501***	17.163***
Hour	-4.124***	-28.037***+	-20.189***+	-10.860***+
Constant	-2.125	-765.332***+	-614.908***+	-360.241***+

	Q(.5)	Q(.75)	Q(.9)	Q(.95)
IFM MW	0.004* +	0.012***+	0.021***+	0.023***+
VERs Cleared	-0.210***+	-0.160***+	-0.106***+	-0.050***+
Net Virtuals	1.476***+	1.409***	1.326***+	1.269***+
San Jose Temp	-6.859***+	-9.686***	-8.613***	-9.698***
Fresno Temp	-10.705***+	-11.763***+	-13.616***+	-14.826***+
LA Temp	17.168***	16.064***	16.100***	-14.826****
Hour	-0.377	9.563***+	17.203***+	21.921***+
Constant	-169.960***+	321.926***+	597.793***+	778.320***+

Note: * p=.05; ** p=.01; *** p=.001;
+ indicates results are statistically significantly different from OLS Model

Model 1: Quantile Coefficients Graphed by Percentile

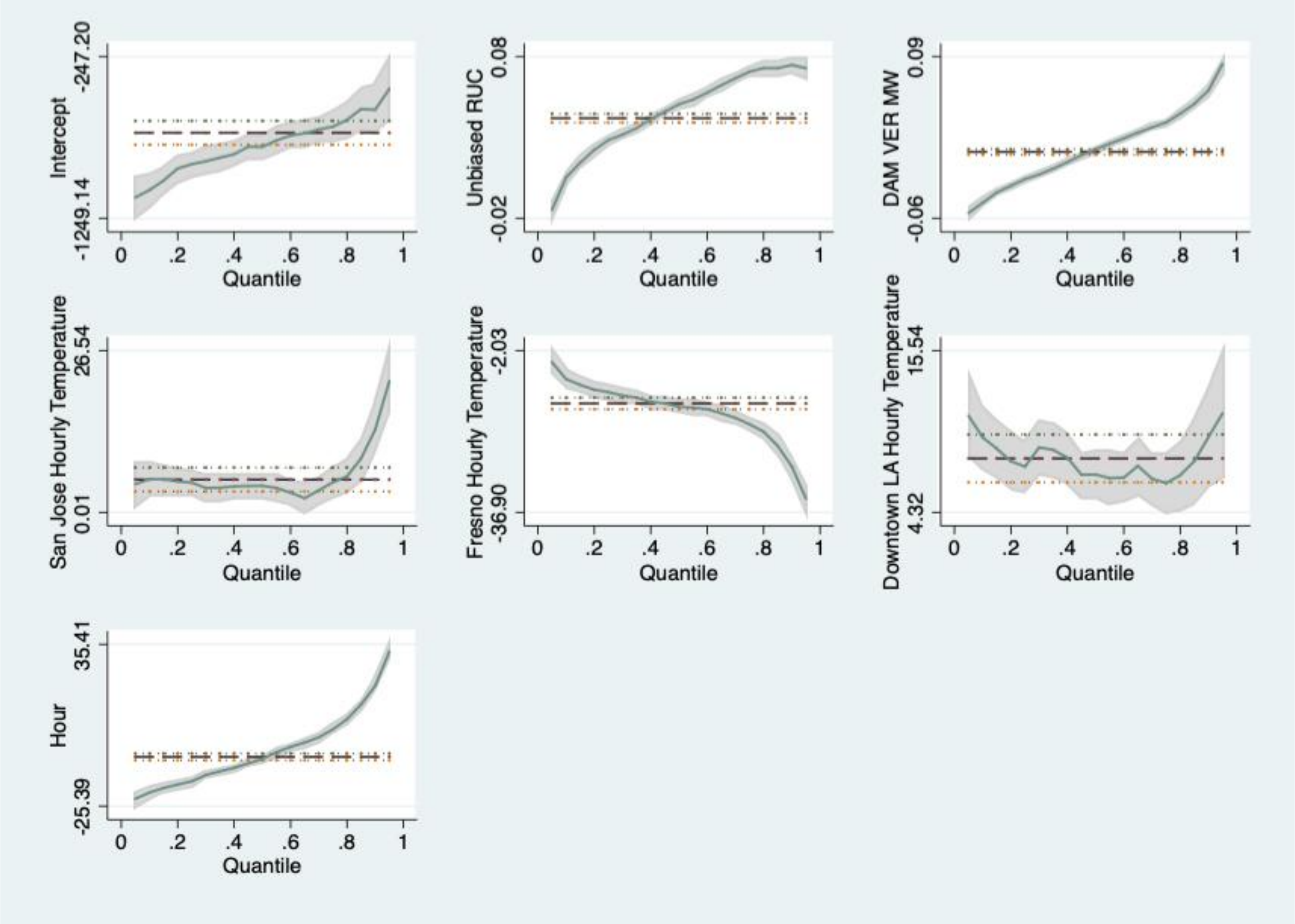


Quantile Regress Results Model 2

	OLS	Q(.05)	Q(.1)	Q(.25)
RUC MW	0.044***	-0.016***+	0.005* +	0.030***+
VERs Forecast	0.001	-0.058***+	-0.048***+	-0.025***+
San Jose Temp	5.381***	4.629*	5.444***	4.879***
Fresno Temp	-13.417***	-4.531***+	-8.171***+	-10.987***+
LA Temp	8.059***	11.019***	9.518***	7.495***
Hour	-6.891***	-22.603***+	-20.317***+	-16.066***+
Constant	-718.142***	-1118.776***+	-1073.269***+	-912.574***+
	Q(.5)	**Q(.75)**	**Q(.9)**	**Q(.95)**
RUC MW	0.053***+	0.075***+	0.079***+	0.077***+
VERs Forecast	0.004* +	0.030***+	0.061***+	0.086***+
San Jose Temp	4.358***	4.930***	13.587***+	21.515***+
Fresno Temp	-14.160***	-17.915***+	-27.036***+	-33.955***+
LA Temp	6.945***	6.343***	9.548***	11.184***+
Hour	-7.710***	3.485***+	19.854***+	32.640***+
Constant	-805.520***+	-680.403***	-575.413***	-446.109***+

Note: * p=.05; ** p=.01; *** p=.001;
+ indicates results are statistically significantly different from OLS Model

Model 2: Quantile Coefficients Graphed by Percentile



Quantile Regress Results Model 3

	OLS	Q(.05)	Q(.1)	Q(.25)
RUC MW	0.044***	-0.017***+	0.004	0.029***+
VERs Forecast	0.001	-0.60***+	-0.049***+	-0.025***+
RUC Net Short	-0.994***	-0.936***+	-0.957***+	-0.989***
San Jose Temp	5.436***	5.421**	5.673***	5.056***
Fresno Temp	-13.446***	-4.847***+	-8.395***+	-10.971***+
LA Temp	8.037***	11.030***	9.831***	7.370***
Hour	-6.854***	-22.567***+	-19.976***+	-16.027***+
Constant	-713.321***	-1109.920***+	-1051.284***+	-905.938***+

	Q(.5)	Q(.75)	Q(.9)	Q(.95)
RUC MW	0.053***+	0.076***+	0.079***+	0.076***+
VERs Forecast	0.004* +	0.031***+	0.061***+	0.086***+
RUC Net Short	-0.999***	-1.035***+	-1.014***	-0.983***
San Jose Temp	4.325***	4.891***	13.353***+	21.571***+
Fresno Temp	-14.148***	-17.906***+	-27.003***+	-33.807***+
LA Temp	6.966***	6.366***	9.775***	10.905***
Hour	-7.699***	3.248***+	19.769***+	32.651***+
Constant	-804.581***+	-698.567***	-581.807***	-425.726***+

Note: * p=.05; ** p=.01; *** p=.001;
+ indicates results are statistically significantly different from OLS Model

Model 3: Quantile Coefficients Graphed by Percentile