Cost-Benefit Analysis of ERCOT's Future Ancillary Services Proposal

Summary of Analysis and Draft Conclusions

PRESENTED TO

ERCOT Stakeholders

PRESENTED BY

Sam Newell
Rebecca Carroll
Will Gorman
Pablo Ruiz

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THE Brattle GROUP

Agenda

Executive Summary

- Brief Summary of the FAS Proposal
- Study Objectives, Scope, and Approach
- Summary of Procurement Reductions Enabled by FAS
- Summary of Cost Savings and Other Benefits

Assumptions and PLEXOS Modeling

- Future Cases Considered
- AS Requirements for FAS vs. CAS
- Participation by Load Resources, New Tech, and Generation

Estimated Benefits of FAS

- PLEXOS Analysis of Day Ahead Energy Opportunity Costs
- Bid Cost Analysis of Real Time Optionality Opportunity Costs

Other Considerations

Executive Summary
Recap of the Context and Motivation for FAS

ERCOT customers spend on average a little over $500 million per year on ancillary services.

AS needs likely to increase over time with growth of inverter-based generation (e.g., wind and solar).

- Lower net load means lower system inertia to support frequency in the event of contingencies. Responsive reserves must increase to provide adequate support.
- Regulation needs may also increase with higher variability of intra-interval net load, but by the same amount between the Current Ancillary Services (CAS) design and the proposed Future Ancillary Services (FAS) design.

At the same time, new technologies offer new ways to meet AS needs.

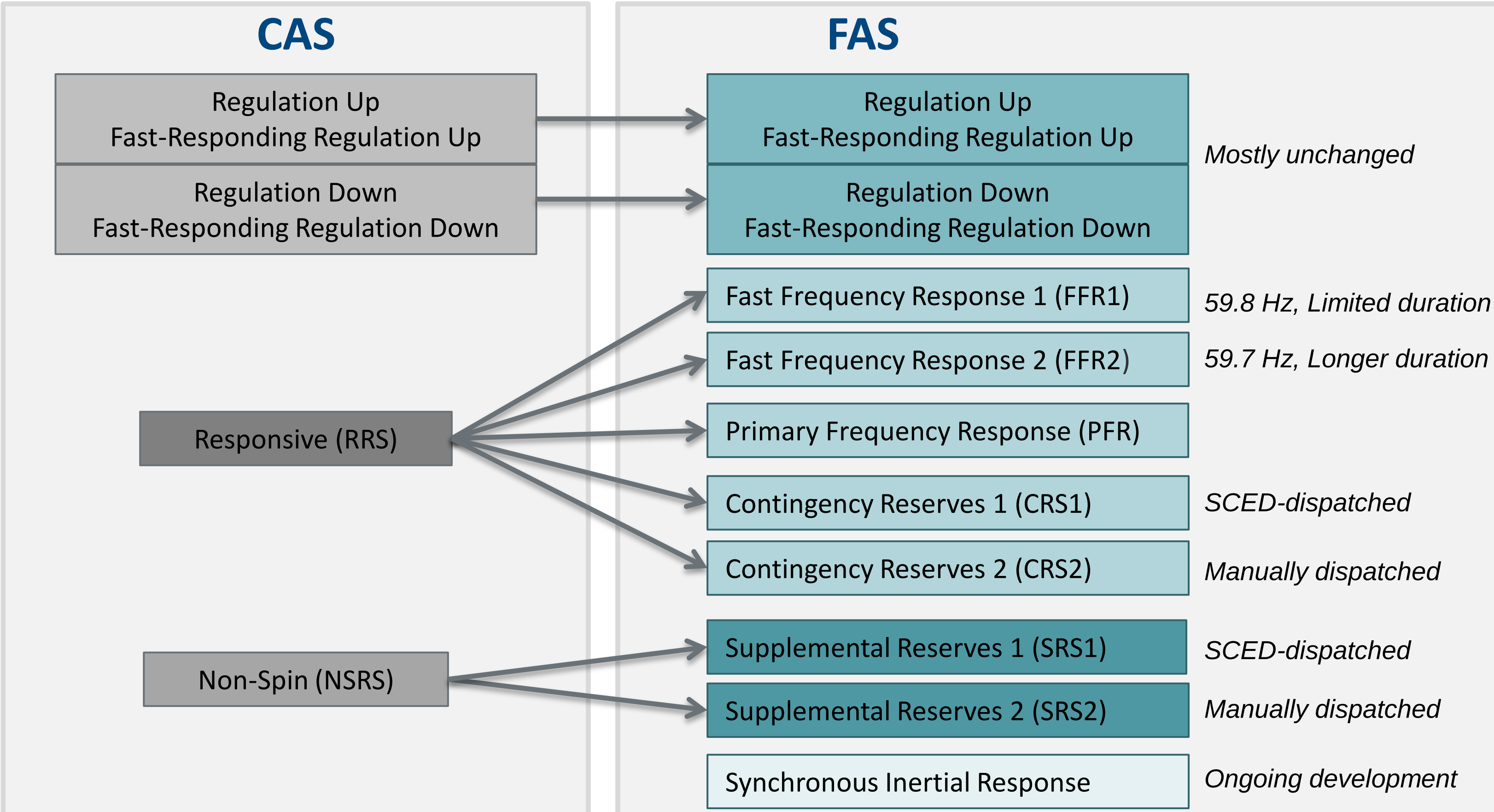
ERCOT proposed FAS to improve efficiency and effectiveness of AS procurement as needs and opportunities grow.

Executive Summary
FAS Design Summary

CAS Shortcomings	FAS Features
RRS product bundles frequency response with contingency response, hence a 1-hour requirement that bars batteries and other fast resources that would be valuable for frequency response	• **Separate out CRS** as its own product, • **Introduce "FFR1"** fast-responding resources at 59.8Hz but must produce for only 10 min. then reset in 10 min • **Convert Load-RRS into "FFR2"** still at 59.7Hz
CAS does not fully recognize the higher value of FFR than PFR during low inertia: • 50% limit on LoadRRS may prevent low-cost, high-value resources from substituting for Gen; • When FFR is lower than planned, 1-for-1 substitution w/PFR would not be enough unless without a buffer	**Recognize greater value of FFR when inertia is low, through equivalency ratio** • Eliminate 50% max on Load/FFR • Eliminate buffer
CAS does not differentiate resources' ability to provide RRS – all have a limit of 20% HSL	**The amount of PFR that a resource is allowed to carry is based on past performance** (usually <20%)
Non-spin requirements are higher than needed under most system conditions	**Replace NS with CRS and SRS that vary with system conditions (much less most of the time)**
Regulation provision may be too concentrated on a few resources with no limits on how much a single resource can provide (except own ramp rate)	**A single resource will be limited to carry up to 25% of the system-wide regulation requirement** so there will always be at least four providers

Executive Summary

Comparison of Products



- Frequency response separated from CRS, and re-formed into PFR and FFR1/2.
- CRS provides similar value to NS: (1) post-contingency, restore frequency response resources; (2) with net load forecast error, meet unexpected needs.
- SRS needs likely to be zero, but product serves as a placeholder.

Executive Summary
Study Objective and Scope

CBA Study Objective: estimate the benefits of ERCOT's FAS proposal compared to CAS

Study Scope: focus on FAS's unbundled products vs. an already-reformed CAS

- We aim to compare FAS to CAS with each providing adequate reliability so we can focus on cost differences.
- CAS has already evolved from a fixed RRS requirement to one that varies with anticipated system conditions, as determined in October for the year.
- Our study assumes requirements are determined day-ahead under CAS and FAS.
- It also assumes Load RRS/FFR prices continue not to account for the shadow price of Max FFR constraints, as today and as proposed for FAS.

Hypothesis: primary value derives from more efficient and effective procurement

- New unbundled frequency response products (and substitution of FFR for PFR at equivalency ratio without a 50% FFR limit) will reduce the quantity of PFR needed from generators, which should avoid unit commitment and dispatch costs.
- Tuning the NS/CRS requirements to system needs (and taking advantage of CRS's 10-min response) reduces the quantity needed from generators, which further reduces costs.
- Value may increase as needs increase and as technology options for providing unbundled products (esp. FFR1 and PFR) increase.

Executive Summary
Study Approach

Consider a range of future scenarios, since system and market conditions will affect AS needs and potential benefits of FAS

- Evaluate 2016 & 2024 “Current Trends” from LTSA scenarios.
- Also assess 2024 “Stringent Environmental” futures from LTSA.

Estimate needs for each product in each case

- Simulate net load, unit commitment, and dispatch in PLEXOS.
- Determine frequency response needs (RRS and PFR/FFR) from inertia calculated from simulated unit commitment and generators’ H-factors for instantaneous loss of 2,750 MW .
- CRS needs are based on amount of reserve needed to restore frequency within normal bounds following a frequency event; varies with system inertia.

Estimate savings from more efficient procurement (i.e., less PFR and NS/CRS)

- Use PLEXOS simulations to calculate day-ahead (DA) production cost savings from reduced unit commitment and improved DA-expected dispatch.
- Estimate additional real-time opportunity cost impacts outside of the model, using historical AS capacity bids (and assuming bids are competitive).

Assess other benefits and costs qualitatively

Executive Summary

Summary of Reductions in AS Procurements

	CAS	FAS	Savings	Comment
Procure Less PFR by recognizing equivalency ratios and allowing more FFR (incl. FFR1)				
2016 Avg MW	1,468	1,329	**140**	Allow > 50% FFR; no need for buffer (see next slide)
2024 Avg MW	1,453	1,325	**129**	Slightly less than 2016 due to higher net load & inertia
2024 Avg MW *w/new tech*	1,453	1,267	**186**	62 MW assumed new batteries reduce avg. PFR by 57 MW; small because residual avg. FFR opportunity (after load resources) is only 62 MW and highly variable
Replace Non-Spin with less CRS and SRS (large overlap in NS/CRS/SRS duty and supply base)				
2016 Avg MW	1,931	1,175	**756**	FAS adapts need to system conditions; and 10-min CRS is more valuable than 30-min NS (so can replace PFR and meet load forecast error with fewer MW)
2024 Avg MW	2,000	1,210	**790**	See above

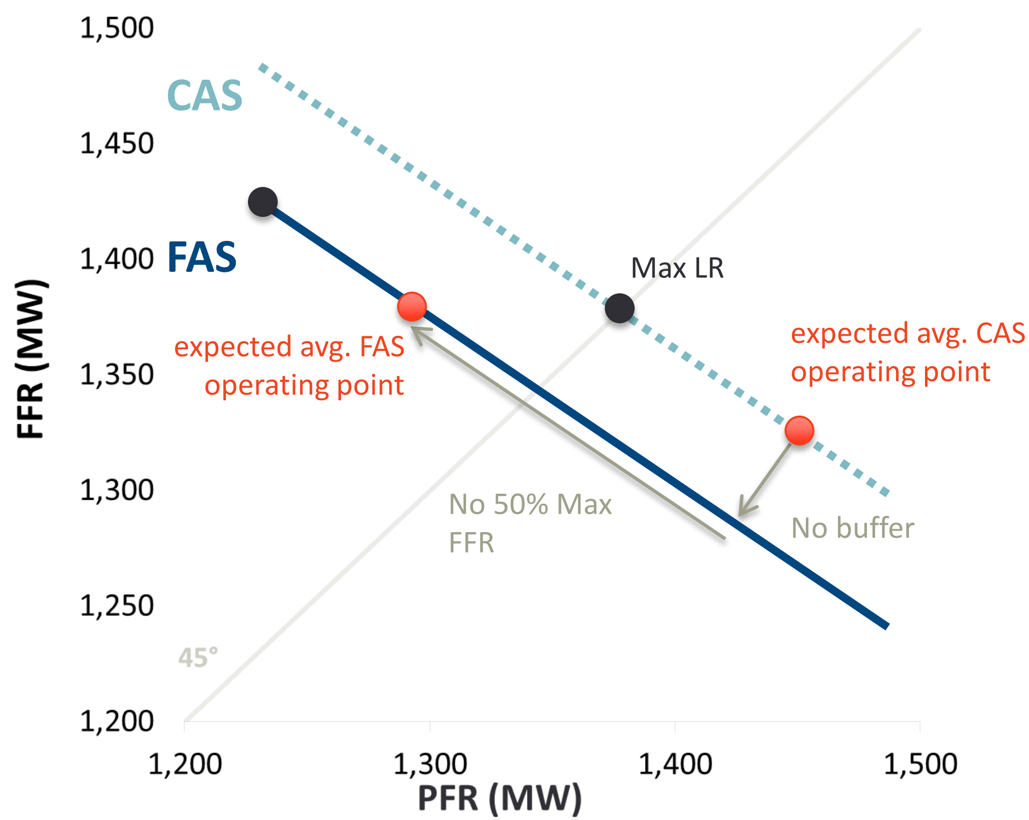
Stringent Environmental not shown

- That scenario turned out *not* to have higher requirements, due to a $45/ton carbon price causing CCs to displace coal for baseload duty. Per MW, CCs have about 1.7-1.8x the inertia of coal units.
- It was not the stress case we had anticipated and therefore did not evaluate further.

Executive Summary
FAS Reduction in PFR Procurement

- **FAS reduces PFR procurement** by allowing more FFR and providing more efficient FFR/PFR substitution (at equiv. ratio). PFR procurement reductions are somewhat modest with high load participation and pushing PFR against the Min PFR limit.
- **"Expected avg. operating points"** assume historical participation rates for Load Resources (96% of Max LR on average): CAS has 1,345 MW on avg.; FAS has 1,369 MW on avg. (2014 saw 1,339 MW avg. LR).
- **"Buffer"** refers to 42 MW extra RRS needed under CAS to maintain sufficient responsiveness 95% of the time (to protect against unexpected reductions in load participation with 1-for-1 substitution of GenRRS in spite of lower value when equivalency ratio > 1); eliminating it reduces expected PFR by 21 MW. See slide 23.
- **Relieving 50% Max FFR** increases FFR and reduces PFR by another 119 MW on average.
- **Average total reduction in PFR is 140 MW**, which reduces commitment & dispatch costs.

Frequency Response in 2016: FAS vs. CAS

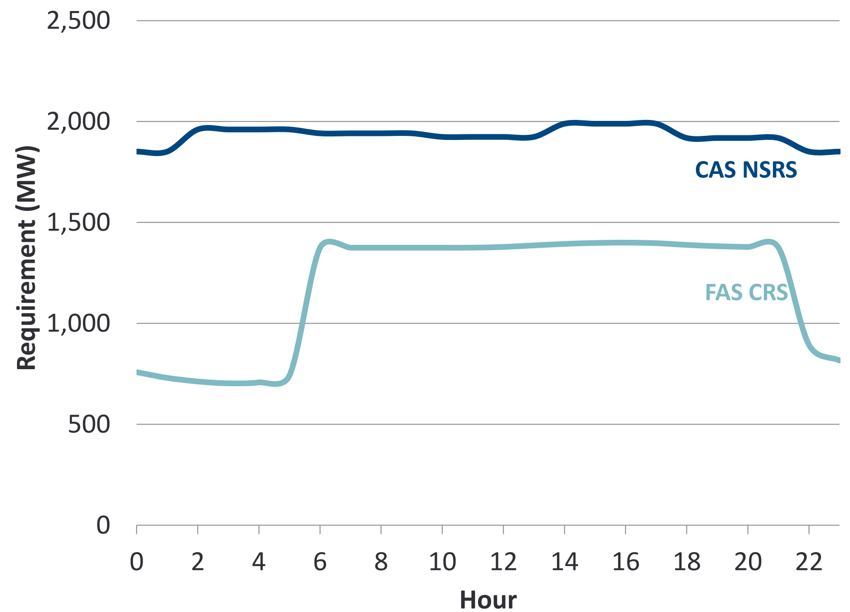


Executive Summary
Non-Spin/CRS Savings

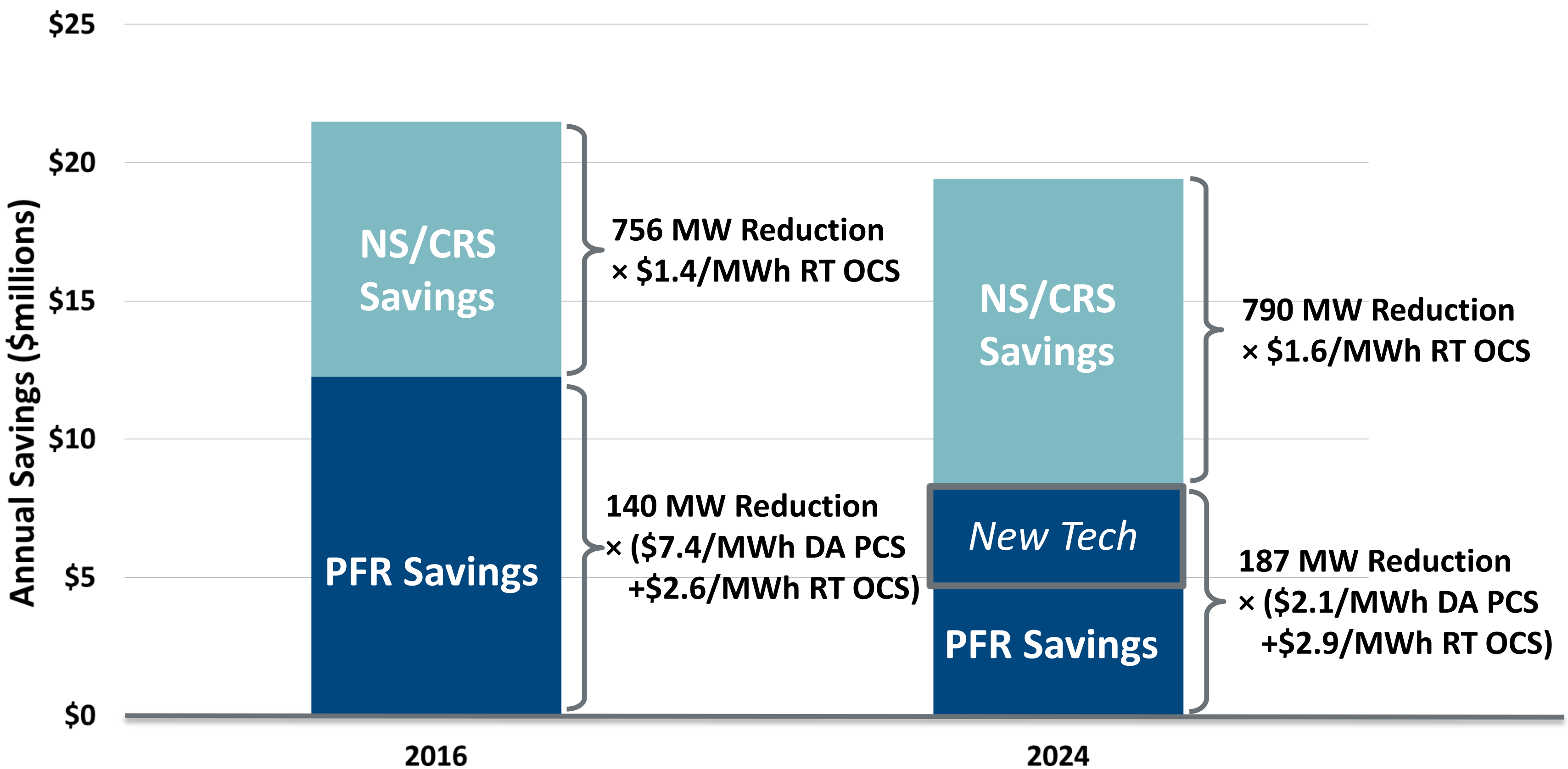
- **We compare NS and CRS because they provide similar duties**:
  - Post-contingency, they allow frequency response providers to back down so it is ready for the next contingency.
  - With forecast errors in net load, NS and CRS respond to unanticipated energy needs.
- **NS and CRS are provided by similar supplies**
  - Largely 10-min startup resources.
  - Thus, reductions in quantity will translate to reductions in cost.
- **FAS maintains reliability with smaller quantities** because:
  - FAS adapts need to system conditions, procuring less off-peak when carrying large amounts of PFR and FFR relative to the load (so don't need as much CRS to bring frequency back 60Hz).
  - Amount is lower even on-peak because 10-min CRS is more valuable than 30-min NS.

CAS Non-Spin and FAS CRS Requirements in 2016

(Average MW by Hour)



Executive Summary
Quantified Annual Benefits



- In 2016, PFR reduction provides high DA production cost savings (DA PCS) per MWh because it enables greater coal dispatch. 2024 has higher net load, so coal is more fully baseloaded.
- Real-time opportunity cost savings (RT OCS) analyzed with historical AS bids.
- Compare these annual benefits to ERCOT's one-time implementation cost of $12-15m and participant costs (unknown).

Executive Summary

Uncertainties and Other Factors

Interpretation of Quantified Benefits

- Benefits should be fairly robust since more efficient procurement by FAS reduces the quantities of PFR and NS/CRS needed.
- A reduction in quantity will save money as long as ancillaries are costly to provide (and the price of ancillaries indicates how much they cost to provide at the margin).
- Incremental benefits of FAS efficiencies would be higher if we hadn't assumed CAS requirements are already tuned to system conditions on a day-ahead basis.

Uncertainties Affecting Quantified Benefits

- Market conditions will change over time (net load, fuel prices, environmental retirements).
  - Differences between 2016 and 2024 show how benefits depend on conditions.
- Modeling uncertainty affects estimated value.
  - PLEXOS savings depends on how the fleet is modeled, e.g., CC operation.
  - Changes between FAS and CAS are small against unit commitment optimization tolerance and lumpiness.
  - Varying our approach on RT opportunity cost savings affects benefits by 0.4x to 1.3x.

Other Factors Not Included

- Net incremental costs of load participation or new tech assumed negligible.
- Did not account for market participants' adaptation costs.
- Other efficiency and reliability benefits we did not quantify (see next slide).

Executive Summary
Non-Quantified Benefits

Flexibility with future developments

- FAS may enable future load resources and other technologies to meet PFR (further reducing generation commitment and dispatch costs) without having to serve CRS duty.
- As NERC-defined frequency response obligation (FRO) decreases over time due to higher participation of FFR, the minimum PFR requirement may decrease.

Reliability improvements with FAS

- FAS removes uncertainty of load resource participation – Operations knows exactly how much FFR is awarded in every hour, and sufficient PFR amount covers requirement balance given the equivalency ratio.
- FFR1 supports frequency at 59.8 Hz instead of 59.7 Hz. Most events would not activate FFR2, so FFR2 will have higher probability of being available for (the next) worst event.
- If deployed, FFR1 can reset in 10 minutes and be ready for the next event.
- In FAS, the amount of PFR that a resource can carry is <u>based on its performance</u> (instead of 20% HSL under CAS), which means that all PFR procured will be deliverable during an event. This will lead to a more distributed PFR supply, which will lead to better frequency response (higher ramp and response less sensitive to the performance of any one resource). All of these factors may result in lower requirements in the future.
- A single resource will be limited to carry up to 25% of the system wide regulation requirement in FAS, leading to a more distributed and reliable response than CAS.

Agenda

Executive Summary

Assumptions and PLEXOS Modeling

- Future Cases Considered
- AS Requirements for FAS vs. CAS
- Participation by LR, New Tech, and Generation

Estimated Benefits of FAS

- PLEXOS Analysis of DA Energy Opportunity Costs
- Bid Cost Analysis of RT Optionality Opportunity Costs

Other Considerations

Assumptions and PLEXOS Modeling

Future Cases Considered

We considered 3 scenarios with progressively more inverter-based generation

- Lower net load should reduce inertia, increasing needs and FAS benefits.
- However, the Stringent Environmental Case turned out not to have higher requirements because of NGCC-for-Coal substitution and NGCCs have greater inertia. Therefore, we did not evaluate further.
- For the remaining 2016 and 2024 CT scenarios, we simulated a CAS case and an FAS change case with all inputs the same except AS requirements.

Supply Resources and Peak Load

Assumptions (in MW unless otherwise noted)	2016 Base Case	2024 Current Trends	2024 Stringent Environmental
Avg. Energy Growth (%)	1.90%	1.60%	1.40%
Peak Load	74,700	82,220	81,230
Total Nameplate Capacity	102,868	113,621	123,420
Thermal Capacity	81,649	85,125	82,228
Seasonal Coal Mothball	1,875	1,875	1,875
Wind Capacity	17,551	21,528	28,204
Solar Capacity	246	3,546	9,246
All Other Capacity	1,547	1,547	1,867

Notes:

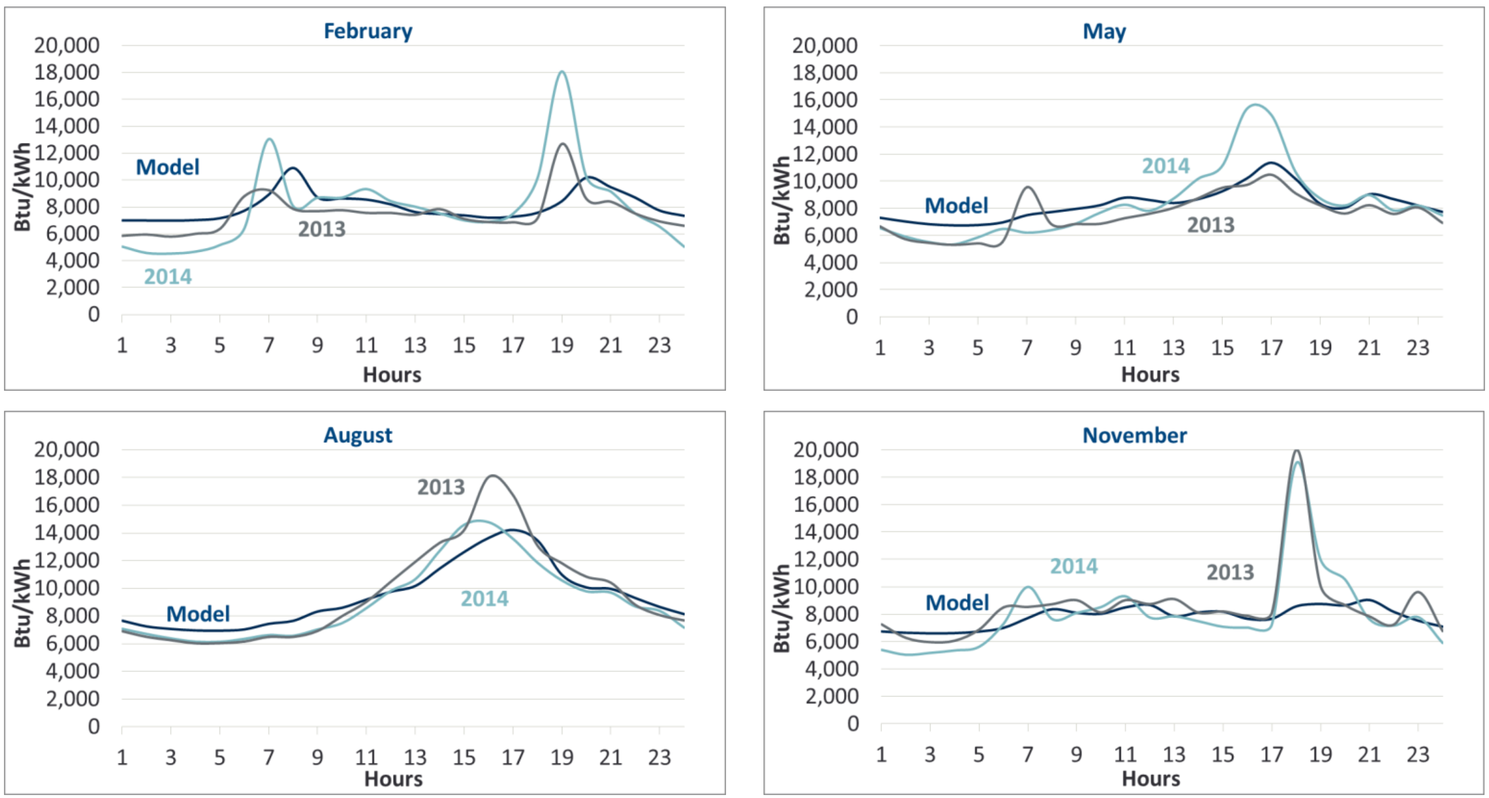
- Includes full Private Use Network (PUN) loads and resources, with generation based on 2014 output.
- Wind and solar output based on 2010 weather patterns.
- Hydro output based on 2010 data.

Assumptions and PLEXOS Modeling

PLEXOS Benchmarking – Energy Prices

The PLEXOS model does not capture RT scarcity prices, but the energy prices and implied market heat rates follow closely to the historical monthly patterns aside from scarcity hours

Implied Market Heat Rate Comparison - Select Months



Assumptions and PLEXOS Modeling

PLEXOS Benchmarking – Ancillary Services

We verified that our 2016 CAS PLEXOS case has the right types of units providing ancillaries by comparing to 2014 data

- Each unit type is providing within 6 percentage points of 2014 actuals.

Procurement breakdown of AS between Provider Types

	2014				2016 CAS Case				Difference (2016 CAS Case - 2014)			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)
Coal	5%	7%	26%	1%	6%	10%	26%	0%	1%	2%	0%	-1%
CC	30%	79%	69%	13%	33%	73%	65%	15%	3%	-6%	-4%	2%
CT & IC	7%	7%	2%	83%	3%	13%	8%	82%	-4%	6%	6%	-2%
Gas Steam	3%	7%	3%	3%	2%	4%	1%	3%	-1%	-2%	-2%	0%
Hydro	7%	0%	0%	0%	9%	0%	0%	0%	2%	0%	0%	0%
Load Resources	48%	0%	0%	0%	48%	0%	0%	0%	0%	0%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**0%**	**0%**	**0%**	**0%**

Assumptions and PLEXOS Modeling

PLEXOS Benchmarking – Ancillary Service Prices

Modeled AS prices are lower than historical because PLEXOS is capturing only day-ahead energy opportunity costs

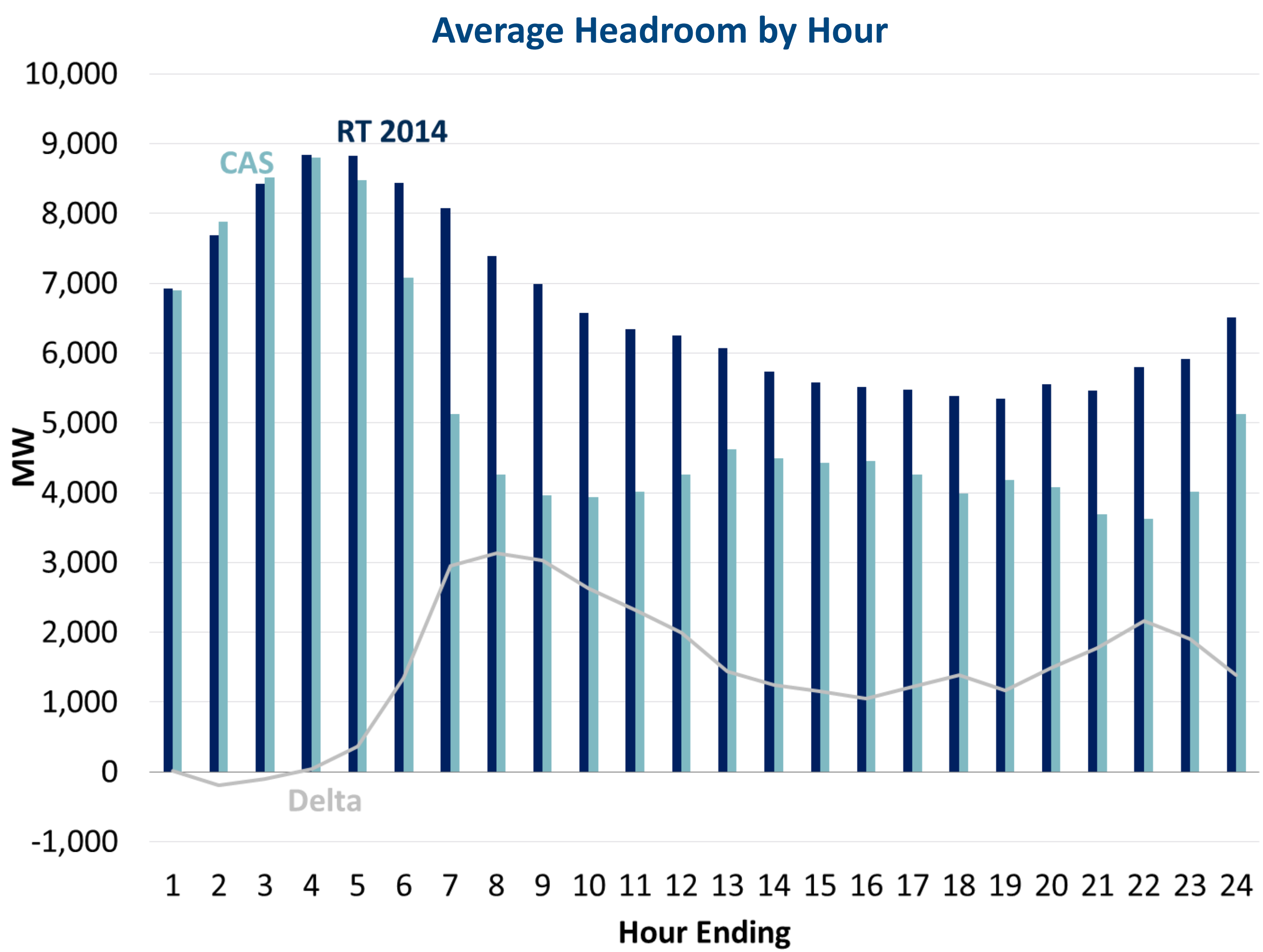
- Actual prices include capacity bids, which were set at 0 in PLEXOS.
- Capacity bids should reflect additional real-time opportunity costs.
- We analyzed real-time opportunity costs outside of PLEXOS (see slides 33-38).

Case	Non-Spin	Regulation Down	Regulation Up	Responsive Reserves
2014 Historical	$5.48	$9.77	$12.48	$14.16
2016 CAS	$0.01	$0.02	$4.25	$4.25

Assumptions and PLEXOS Modeling

PLEXOS Benchmarking – Unit Commitment

- "Headroom" represents the amount of online thermal capacity minus thermal output.
- Lower headroom in PLEXOS than the real world indicates a tighter commitment.
- Tighter commitment may tend to understate inertia and overstate RRS requirements (and FAS benefits).



Assumptions and PLEXOS Modeling

System Inertia

- For each case, ERCOT staff calculated hourly system inertia from PLEXOS unit commitment and H-factors for each unit.
- 2024 net load and inertia are higher on average than in 2016 because load increases more than renewable generation (but not always—see next slide).
- Somewhat surprisingly, Stringent Environmental had higher inertia than other cases in spite of lower net load. This is due to a $45/ton carbon price causing CCs to displace coal for base load duty.

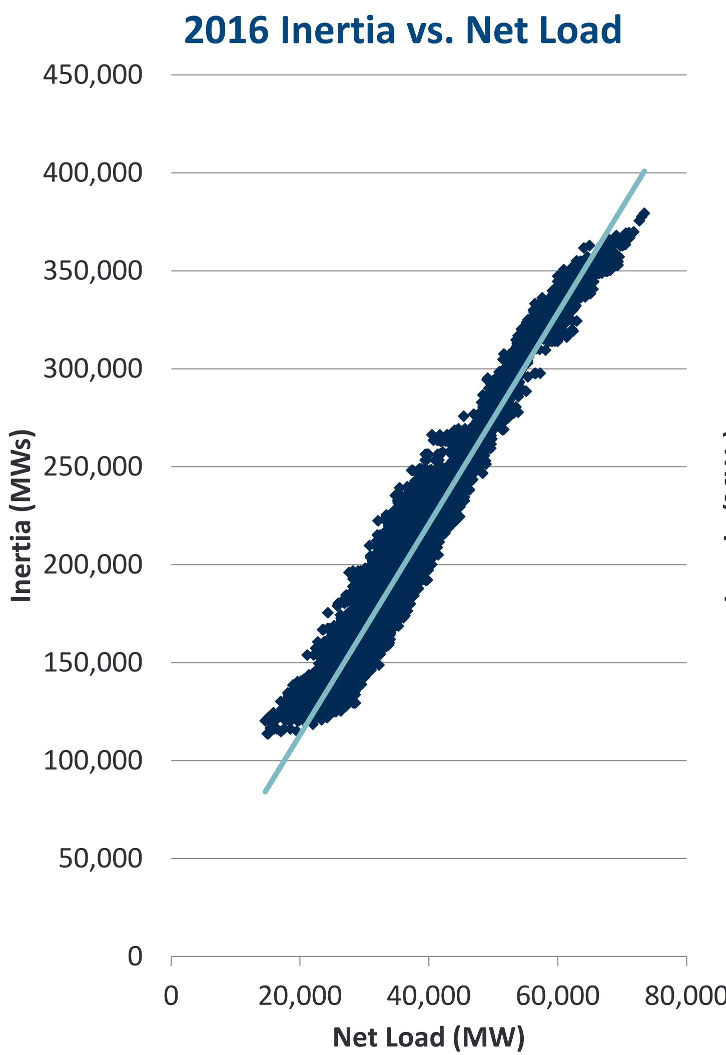
Net Load and Inertia

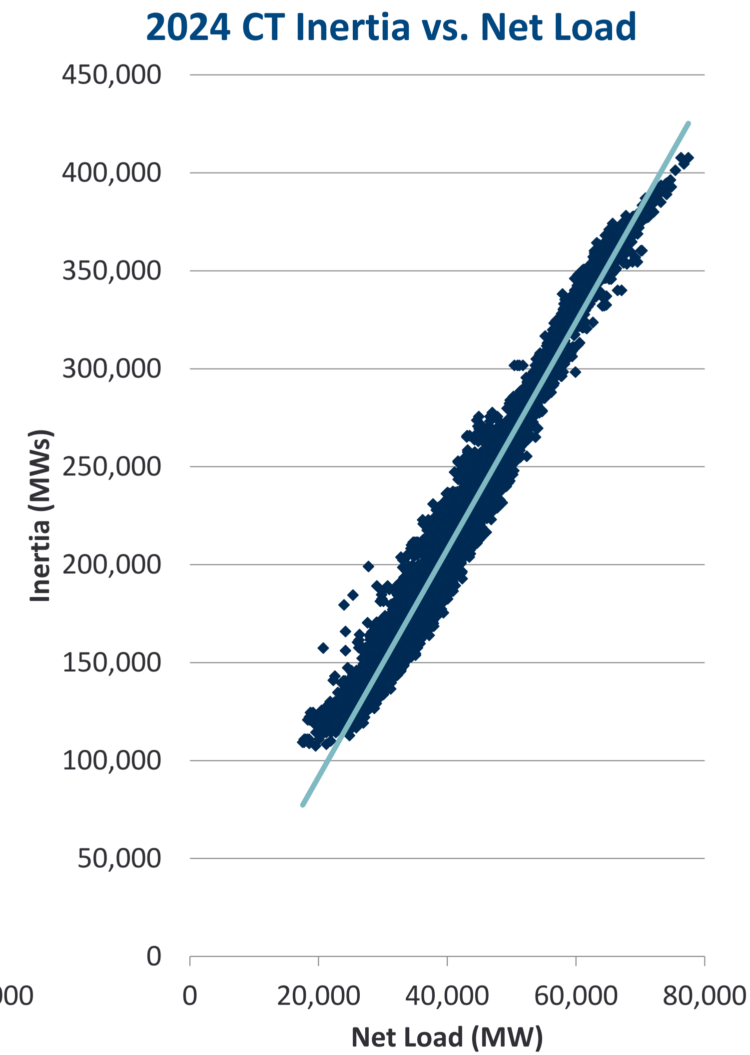
		2016	2024 CT	2024 SE
Load (MW)	**Average**	45,167	51,393	50,828
Renewable Gen (MW)	**Average**	6,959	9,419	13,982
Net Load (MW)	**Average**	38,209	41,974	36,907
	Max	73,450	77,487	71,908
	Min	14,616	17,553	11,457
Inertia (MWs)	**Average**	211,129	219,076	235,132
	Max	379,334	407,725	376,781
	Min	113,692	107,423	89,887

Assumptions and PLEXOS Modeling

Hourly System Inertia vs. Net Load

- Increased renewable generation in 2024 reduces inertia and net load in a few hours (but not on average).
- However, greater usage of high-inertia CCs increases system inertia.

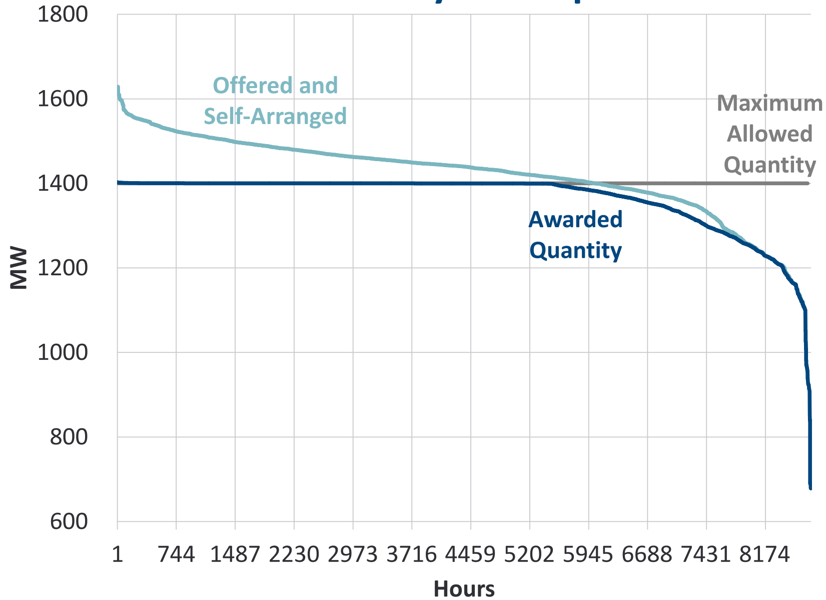




Assumptions and PLEXOS Modeling
Assumed Participation by Load

- Historically load resources provided the max during most hours, e.g., 64% of the time in 2014; but otherwise less
- For our study, we applied the 2014 participation rates (averaged by daily hour within each month) to the max opportunity in each hour
- Results in 96% on average
- LR MW are similar to 2014, so no major growth or attrition implied
  - 2014 saw 1,339 MW avg.
  - CAS has 1,345 MW on avg.
  - FAS has 1,369 MW on avg.
- Assume no incremental costs of these small increases in load participation since no operating cost except in rare deployments
- Note that most load resources have historically been price takers, so we model them that way

2014 Hourly Participation



Historic Load Resource Participation

	2011	2012	2013	2014
Max	100%	100%	100%	100%
Min	42%	42%	60%	48%
Avg	96%	90%	94%	96%
Median	100%	94%	97%	100%

Assumptions and PLEXOS Modeling

Assumed Participation by New Tech

- There opportunity for FFR beyond existing load resources is small.
  - Some observers may have expected FAS to create a large opportunity for new tech.
  - However, as discussed, inertia does not get as low by 2024 as originally anticipated (not even in Stringent Environmental), and existing load resources fill most of the FFR opportunity before the Min PFR constraint binds .
- Technologies and costs considered: Initial screening was done on Flywheels, CAES, Market DR, C&I DR, NaS Batteries, and Li-ion Batteries.
- We chose to model Li-ion batteries as the representative new tech due to their relatively low capital costs.
- Assumed capital costs are between $400/kW and $1,800/kW.
- However, we assumed net incremental costs are negligible.
  - New tech has capital cost but would displace some marginal conventional capacity, saving capital costs and affecting production costs.
  - For example, for a 200 MW battery, the incremental costs would be 200MW*[CONEct – CONEbatt] – PCS associated with 200 MW CTs foregone.
    Any unmodeled scarcity value cancel out assuming both batteries and CTs would be online.
  - The net difference is likely low, but may provide additional savings if batteries are more than economic up to the FFR limit.

Assumptions and PLEXOS Modeling

Assumed RRS "Buffer" under CAS

- **If CAS defined a static requirement, such as 1400 MW, we'd have two problems**:
  - Actual needs depend on system inertia.
  - When load participation is low and Gen RRS substitutes 1-for-1 (but provides less value when inertia is low), responsiveness may be too low.
- **CAS has already *partially* addressed these problems**
  - Requirements set in October to vary by time period, with expected inertia.
  - We further assume in our study that RRS needs are defined day-ahead given greater information of inertia and expected load participation.
  - But even that is not enough if load participation is *unexpectedly* low and generation substitutes 1-for-1.
- **We determined a "buffer"** that would be added to the RRS requirement in each hour-month (e.g., hour 1 of each day in January) to ensure adequate responsiveness 95% of the time
  - Assumed average load participation as the expected value.
  - Treated variation within each hour-month as a random variable.
  - The result was 42 MW on average for 2016.
  - Varies by hour(1-24)/month from 0 to 280 MW.
  - Similar for 2024.

Assumptions and PLEXOS Modeling

Resulting AS Requirements

2016 Average Requirement (MW)

	CAS	FAS	(FAS - CAS)
Reg Up	460	460	-
Reg Down	456	456	-
RRS	2,814	-	-
PFR+FFR (In PFR Terms)	-	3,245	-
Expected FFR	1,345	1,369	24
Expected PFR	1,468	1,329	(140)
CRS	-	1,175	-
NSRS	1,931	-	-
SRS	-	-	-

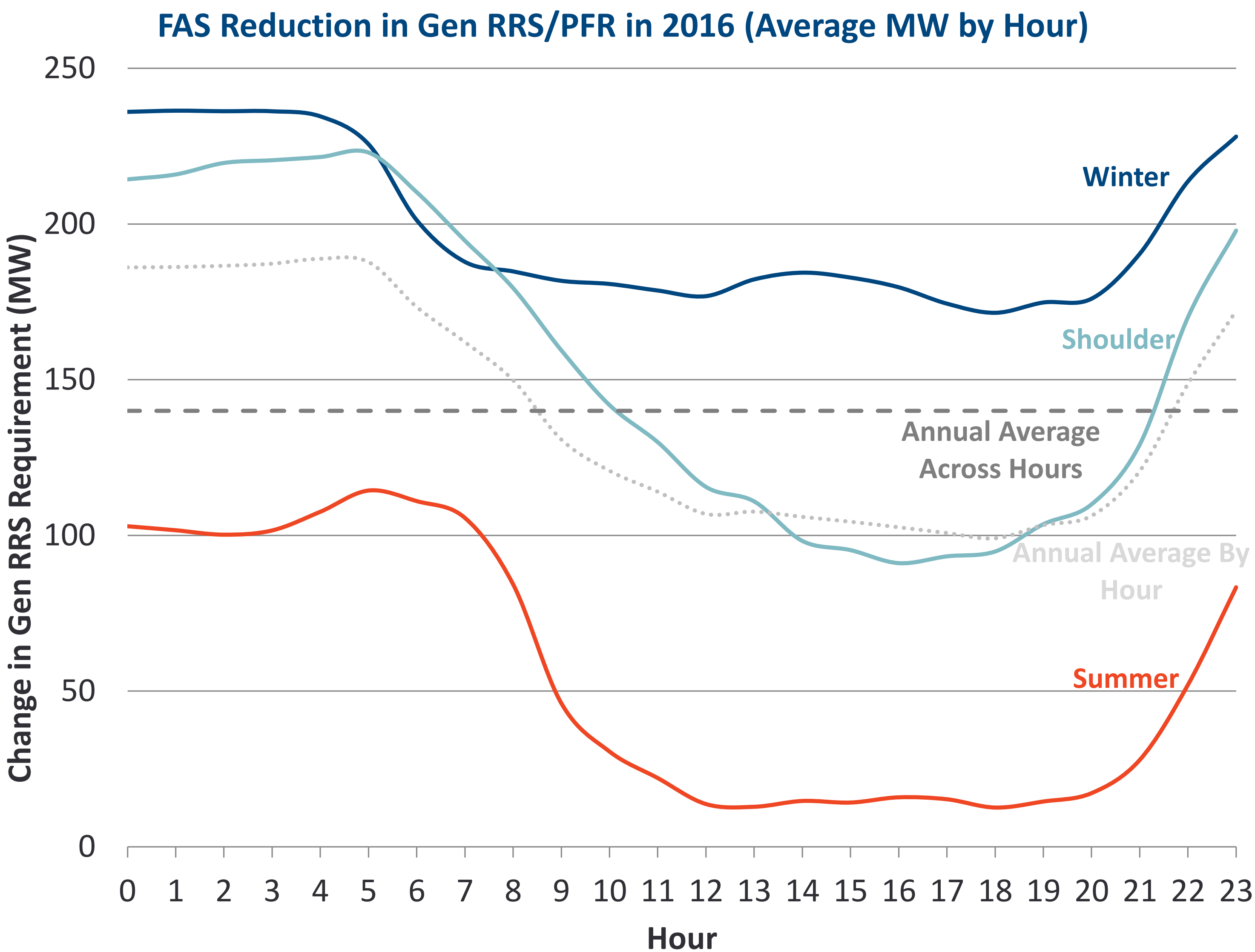
2024 Average Requirement (MW)

	CAS	FAS	(FAS - CAS)
Reg Up	499	499	-
Reg Down	495	495	-
RRS	2,785	-	-
PFR+FFR (In PFR Terms)	-	3,165	-
Expected FFR	1,332	1,345	13
Expected PFR	1,453	1,325	(129)
CRS	-	1,210	-
NSRS	2,000	-	-
SRS	-	-	-

- Because FAS is more dynamic, the requirements are defined without a buffer. In 2016, 21 MW of the Expected PFR savings under FAS comes from the lack of buffer, in 2024 it is 37 MW.
- Eliminating requirement for 50% max FFR increases the expected FFR and reduces PFR by another 119 MW on average in 2016 and 92 MW in 2024.

Assumptions and PLEXOS Modeling

PFR Savings Vary by Hour



Agenda

Executive Summary

Assumptions and PLEXOS Modeling

- Future Cases Considered
- Product Definitions & Requirements
- Participation by LR, New Tech, and Generation

Estimated Benefits of FAS

- PLEXOS Analysis of DA Energy Opportunity Costs
- Bid Cost Analysis of RT Optionality Opportunity Costs

Other Considerations

Estimated Benefits

PLEXOS DA Production Cost Impacts (2016)

- **FAS reduces production costs by $9.1 million/yr**
  - $1.8 million are savings from avoided startup costs.
  - The rest are from dispatching lower marginal cost units as they provide less reserves or are backed down less by other units being committed and sitting at min load.
- **2016 cost savings has largely to do with CCs vs. coal**
  - FAS's reduction in PFR, especially in the winter late night/ early morning, allows some CC units to be decommitted.
  - With greater CC commitment for reserves in CAS, CCs' LSL generation causes coal units to back down from HSL.
  - In the FAS case the same coal units can operate at HSL.
- **Prices decrease slightly**
  - FAS's lower PFR procurement reduces prices for RRS/PFR and Reg Up.
  - But price reduction is different from production cost savings. Production cost savings is nearly a PΔQ effect, not a QΔP effect.

Annual Production Costs ($m)

Case	Production Costs
CAS	$10,416
FAS	$10,407
Savings:	**$9.06**

Annual Average Price ($/MWh)

	2016	
Product	**CAS**	**FAS**
Energy	$36.16	$36.58
Non-Spin or CRS	$0.01	$0.04
Regulation Down	$0.02	$0.07
Regulation Up	$4.25	$3.35
RRS or PFR	$4.25	$3.31

Estimated Benefits

PLEXOS DA Production Cost Impacts (2024)

- **FAS reduces total system production costs by $1.2 million without New Tech and another $2.2 million with New Tech**
- **Savings are less than in 2016**
  - Net load is higher, and the tradeoff in the supply stack is among CC units with only slightly different heat rates.
  - The average cost trade-off among CCs is only ~$1.30/MWh, which leads to much smaller production cost savings than in 2016.
- **As in 2016, FAS lowers RRS/PFR and Reg Up prices; New Tech further reduces them**

Annual Production Costs ($m)

Case	Production Costs
CAS	$14,685
FAS	$14,684
FAS NT	$14,682
FAS Savings:	**$1.24**
w/ NT Savings:	**$3.39**

Annual Average Prices($/MWh)

	2024		
Product	**CAS**	**FAS**	**FAS NT**
Energy	$48.64	$48.93	$48.82
Non-Spin or CRS	$0.12	$0.16	$0.18
Regulation Down	$0.01	$0.02	$0.02
Regulation Up	$5.30	$4.91	$4.70
RRS or PFR	$5.30	$4.95	$4.78

Estimated Benefits

Inclusion of Real-Time Opportunity Costs

PLEXOS informs DA opportunity cost but not the additional RT optionality foregone by committing capacity for reserves

- DA opportunity costs are accounted for in prices and production costs by way of the co-optimized, simultaneous energy and AS DA market—both in the real-world and in PLEXOS.
- But providers of AS bear an additional cost when they commit their capacity for reserves and lose RT optionality to:
  - Sell energy when RT prices are high enough (see example next slide).
  - Shut down unit when RT prices are low enough.
  - The magnitude of foregone option value depends on RT price volatility.
- The foregone optionality constitutes real social costs (as do DA production costs).
- In the real world, AS providers can represent RT opportunity costs as "capacity bids" that form their competitive offer for providing AS.
- PLEXOS also admits such capacity bids but does not inform what they should be.

We chose to analyze FAS's RT OC savings outside PLEXOS

- Used historical capacity bids provided by ERCOT.
- Could have added these AS bids to PLEXOS, but that would have added false precision, given our limited understanding of how bids vary by unit and unit type.
- Analyzing RT OC savings outside the model allows us to separate this benefit from DA production cost benefits, which helps since they are affected by different uncertainties.

Estimated Benefits
Foregone RT Optionality: Example

	DA Market	RT Market	
Energy price	$50/MWh	$48/MWh	with 50% probability
		$52/MWh	with 50% probability

- Assume a marginal unit in DA, with incremental costs of $50/MWh.
- Without committing unused capacity to AS, the unit can expect to earn $1/MWh RT net revenues:
  - 50% of the time RT prices are $48, and the capacity used to sell energy in DA earns $2/MWh buying back energy at $48/MWh.
  - 50% of the time RT prices are $52 , and the capacity earns no incremental net revenues (still generates and is still paid the DA price of $ 50).
- If the unit sells AS and is not called to deliver energy in RT, its RT net revenues from the capacity providing AS are $0/MWh.
- Thus the unit incurs a $1/MWh opportunity cost for every MW of AS sold in DA.

Estimated Benefits
RT Opportunity Cost Analysis Framework

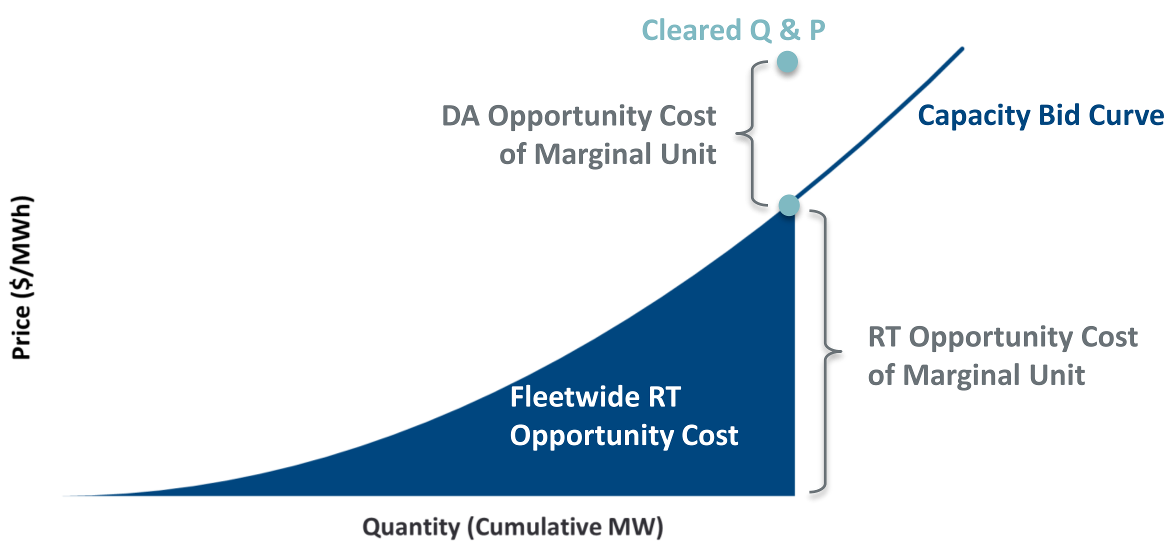
Purpose: Estimate the real-time opportunity cost savings from reduced procurement of non-spin and responsive reserves under FAS

- **Data Provided**
  - 2014 hourly generating capacity offers into AS Markets (offer curve): we assume these bids are competitive and represent real-time optionality foregone
  - 2014 Settlement prices and quantities
  - DA energy opportunity cost of providing AS estimated from PLEXOS for 2016
  - FAS and CAS AS requirements for 2016 and 2024
- **Estimate 2014 RT Opportunity costs**
  - For each hour, identify the marginal provider on the bid curve
  - Assume bids are competitive and reflect RT opportunity costs
  - Calculate the integrated area under the offer curves (not P*Q)
- **Estimate Costs for each Study Case** by scaling the 2014 costs based on requirements relative to 2014
  - Apply the average $/MWh cost from each month-hour in 2014
  - Assumes supply will adjust to keep the average cost stable
  - This is conservative when estimating the value of *reductions* in requirements (accounting for upward-sloping cost curve would show greater marginal savings)

Estimated Benefits
Analysis of 2014 Bids and Associated Costs

- The marginal unit is determined by comparing the settlement price to an individual unit's bid on the offer curve (after removing the energy opportunity cost)
- The fleetwide RT opportunity cost is the area under the offer curve
- The average cost ($/MWh) for each hour is the fleetwide cost divided by quantity

Method for Calculating Fleetwide RT Opportunity Costs from Capacity Bids



Estimated Benefits
Estimated RT Opportunity Costs from 2014

2014 Reference Case		RRS	NS
Actual Avg. Quantity (MW)	[1]	1,416	1,377
Actual Total Quantity (MWh)	[2]	12,398,856	12,060,630
Actual Payments ($thousands)	[3]	$178,671	$67,143
Actual Avg. Price ($/MWh)	[4]	$14.16	$5.48
Est. DA Opportunity Component ($/MWh)	[5]	$4.26	$0.01
Est. RT Opportunity Component ($/MWh)	[6]	$9.90	$5.47
Estimated RT Fleetwide Oppy Cost ($thousands)	[7]	$29,936	$18,160
Estimated Avg. RT Fleetwide Oppy Cost ($/MWh)	[8]	$2.41	$1.51

Sources and Notes:
[1] = Average quantity procured over all hours in 2014
[2] = Total quantity procured over all hours in 2014
[3] = Sum product of settle price and settle quantity for all hours in 2014
[4] = Average settle price in 2014
[5] = Estimate Day Ahead opportunity cost using results from 2016 CAS PLEXOS results
[6] = [4] – [5]
[7] = Area under the hourly bid curves. Does not include DA Opportunity costs from PLEXOS
[8] = [7] / [2] (Note: less than RTOC price because average cost over the fleet is less than that of the marginal price)

- Average RRS costs are ¼ the estimated RT OC component of RRS price, which is 2/3 total price
- Average NS cost is less than ¼ the NS price (DA OC approx. zero); assume this applies to CRS/SRS
- For each product, we apply the average costs for each hour-month to the procurements for the same hour-month in future CAS and FAS cases (so cost scales with the amount procured)
- This assumes opportunity costs are invariant as system conditions and AS framework change

Estimated Benefits

Bid Cost Analysis Results

Cost Reductions Driven by Change in AS Procurements and RT Volatility

- Moving from CAS to FAS reduces RT Opportunity costs for both PFR and CRS.
- Future savings may be higher or lower, depending on how technology development affects real-time volatility:
  - May increase with higher wind and solar penetration;
  - May decrease with higher storage penetration, more active demand participation in RT markets, or with look-ahead SCED.

Case	Metric	RRS			Non-Spin		
		CAS	FAS	Savings	CAS	FAS	Savings
2016	Avg. Quantity (MW)	1,468	1,329	140	1,931	1,175	756
	Total Fleetwide RT Oppy Cost ($Millions)	$32.3	$29.2	$3.2	$26.5	$17.2	$9.2
	Avg. RT Opportunity Cost ($/MWh)	$2.5	$2.5	$0.0	$1.6	$1.7	-$0.1
2024	Avg. Quantity (MW)	1,453	1,325	129	2,000	1,210	790
	Total Fleetwide RT Oppy Cost ($Millions)	$37.4	$34.1	$3.3	$32.0	$20.8	$11.2
	Avg. RT Opportunity Cost ($/MWh)	$2.9	$2.9	$0.0	$1.8	$2.0	-$0.1
2024 w/ NT	Avg. Quantity (MW)	1,453	1,267	187	2,000	1,210	790
	Total Fleetwide RT Oppy Cost ($Millions)	$37.4	$32.6	$4.8	$32.0	$20.8	$11.2
	Avg. RT Opportunity Cost ($/MWh)	$2.9	$2.9	$0.0	$1.8	$2.0	-$0.1

Note: All dollar values reported above are nominal

Agenda

Executive Summary

Assumptions and PLEXOS Modeling

- Future Cases Considered
- AS Requirements for FAS vs. CAS
- Participation by LR, New Tech, and Generation

Estimated Benefits of FAS

- PLEXOS Analysis of DA Energy Opportunity Costs
- Bid Cost Analysis of RT Optionality Opportunity Costs

Other Considerations

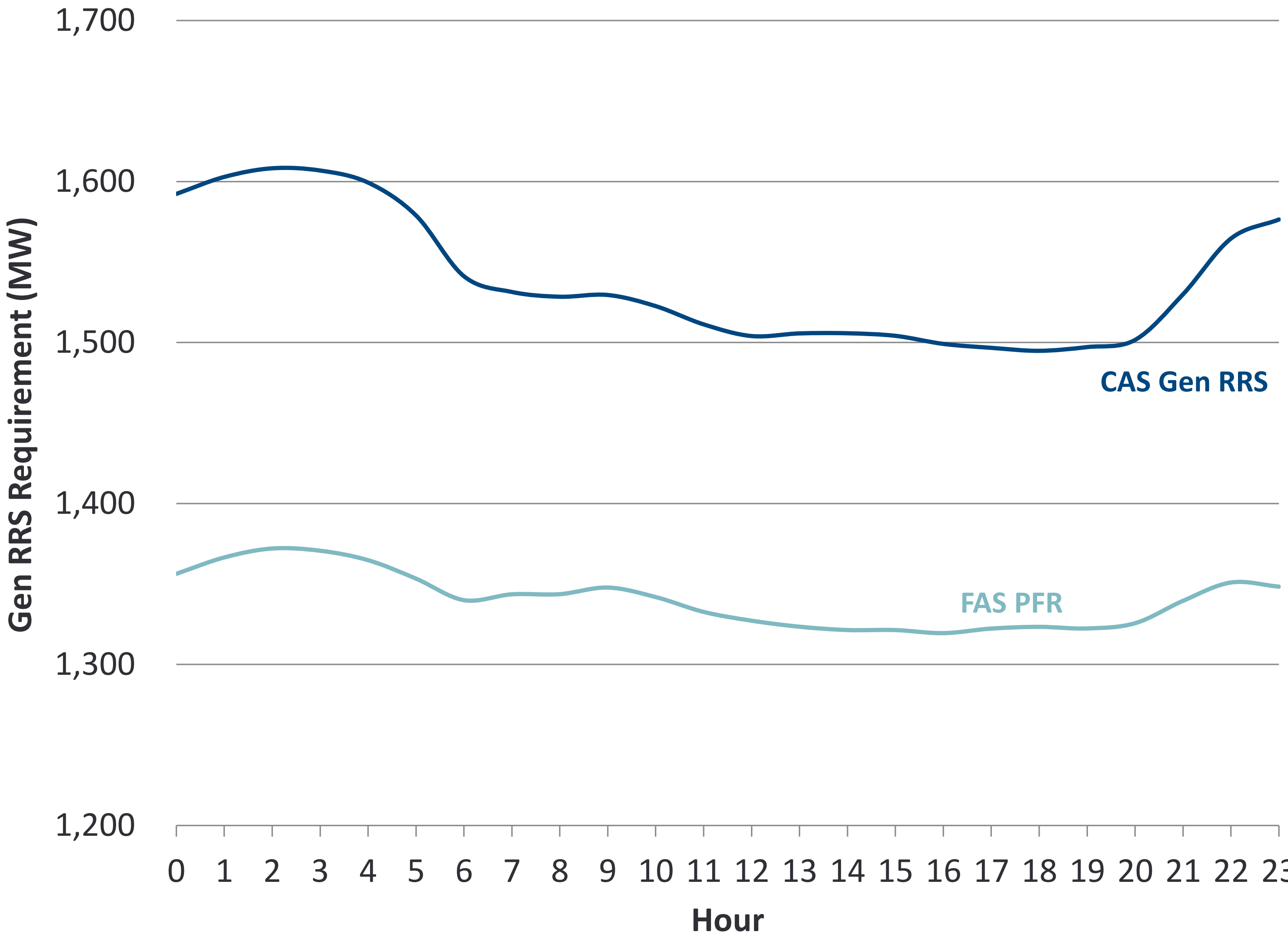
Other Considerations
Procurement approach

- ERCOT proposes to define its FAS requirements on a day-ahead basis when it has a good forecast of net load, inertia, and thus AS needs. This tunes procurement to the needs of the system.
- However, some market participants have raised concerns about their ability to predict the needs and to procure and hedge accordingly; they have proposed some alternatives that would determine needs further in advance.
- We do not believe ERCOT should adopt these alternatives because they may be economically inefficient and they are not necessary.
  - They procure more reserves than needed – they would have to include a sizable buffer to be prepared all the time for the lowest inertia conditions that may occur only rarely. It is comparable to fixing the hourly load forecast at a level above expected loads, then enforcing that load physically by loading up banks of resistance heaters.
  - And those options are not necessary for providing certainty to load serving entities if the market develops ways to hedge the quantity uncertainty financially. We expect that the market can if ERCOT establishes clear procedures for determining the quantities so market participants can forecast them.
- Thus we only evaluated the day-ahead option.

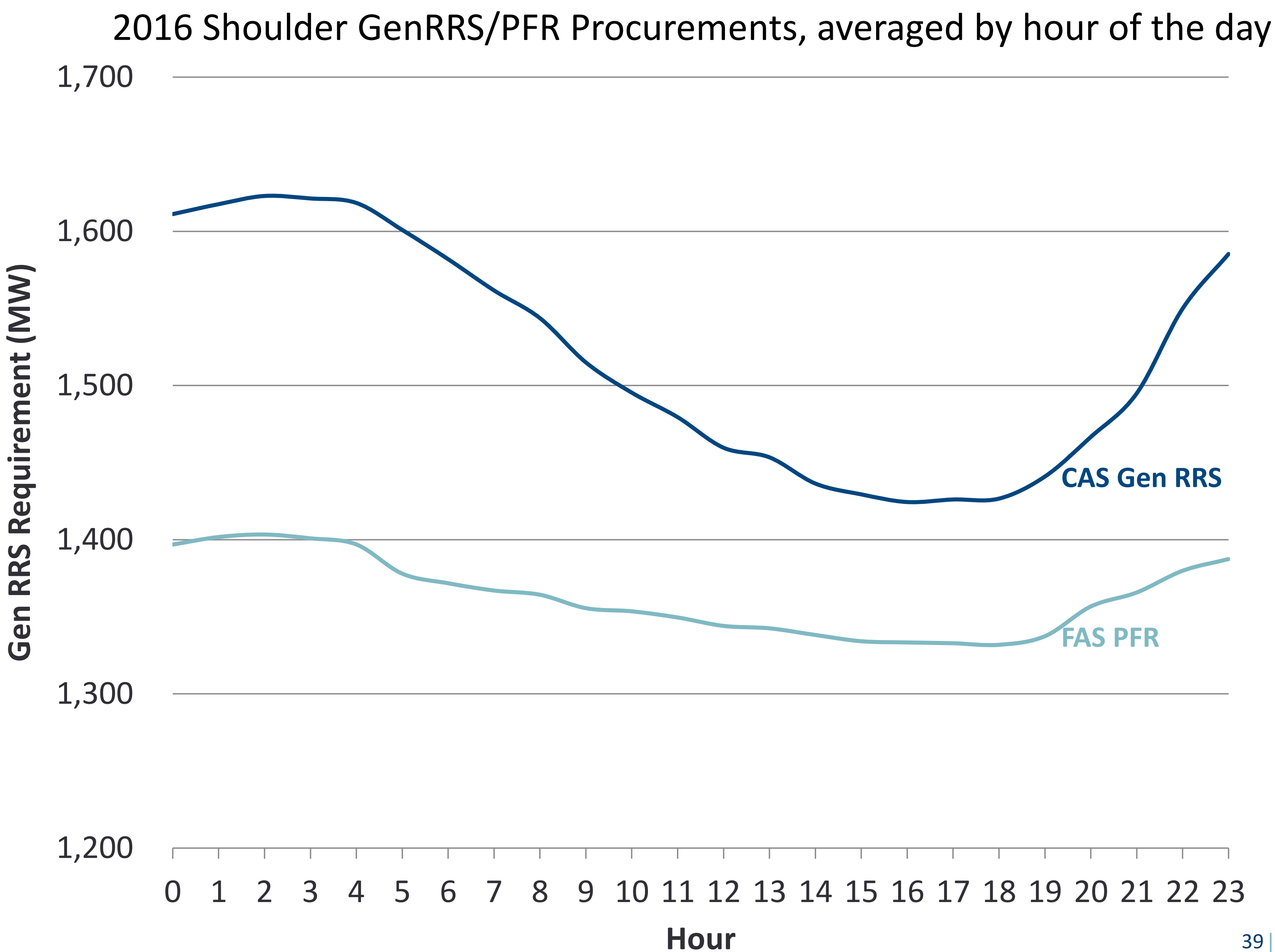
Appendix

Appendix
Estimated AS Requirements

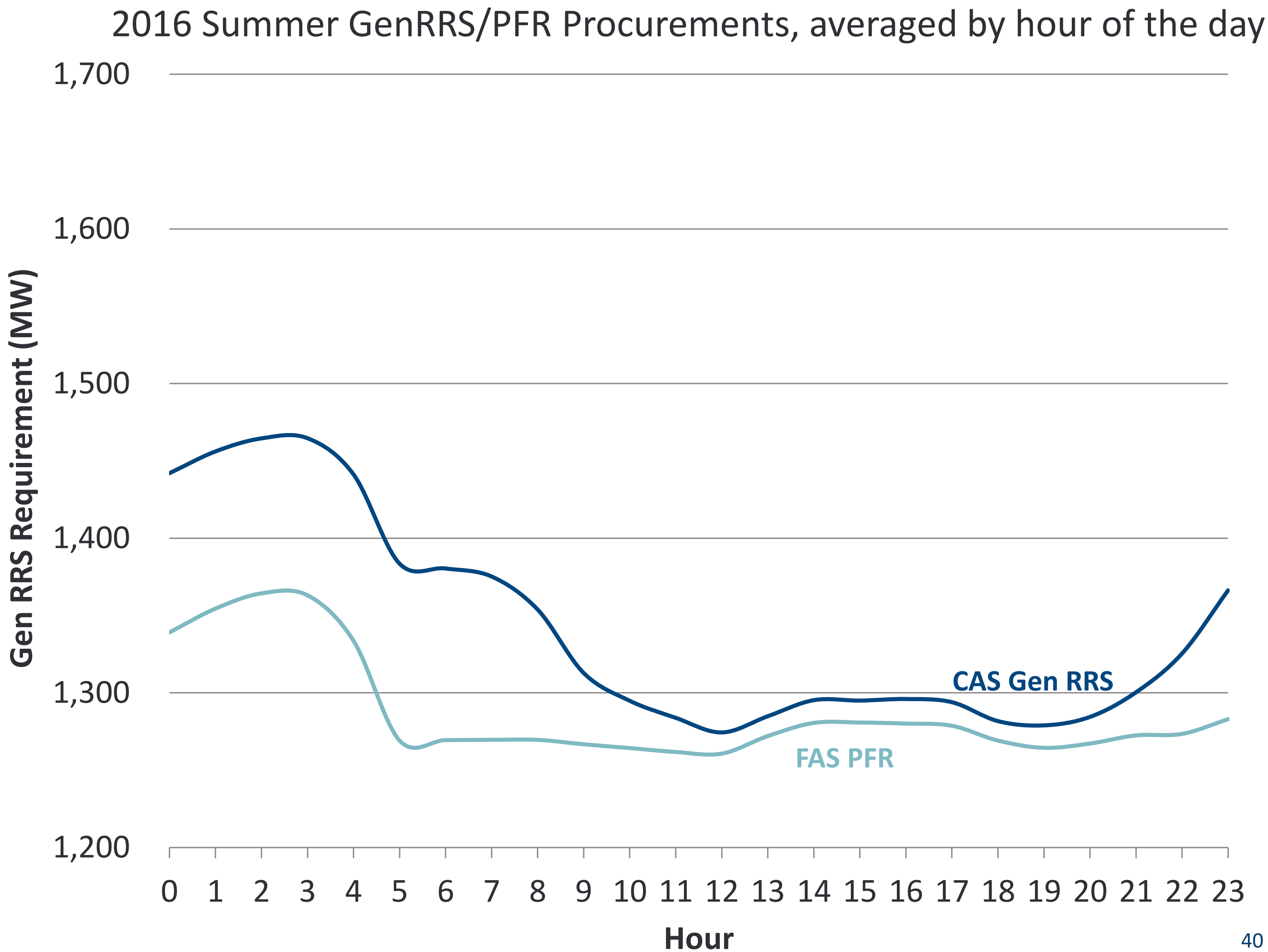
2016 Winter GenRRS/PFR Procurements, averaged by hour of the day



Appendix
Estimated AS Requirements



Appendix
Estimated AS Requirements



Appendix
Thermal Unit Characteristics

Generator Type	Ramp Rate	Minimum Up Time	Minimum Down Time	Variable O&M	Fleet Average Characteristics: Offline Non-Spin Capability	Regulation Down Capability	Regulation Up Capability	Responsive Reserve Capability	Full Load Average Heat Rate
	MW/min	Hrs	Hrs	$/MWh	%	%	%	%	Btu/kWh
Nuclear	3	-	-	$2.5	-	-	-	-	10,168
Coal	4	24	12	$6.0	-	3%	3%	17%	10,400
Combined Cycles*	10	8	4	$2.5	2%	10%	10%	14%	7,580
CT & IC**	4	1	1	$7.5	28%	13%	13%	7%	12,575
Gas Steam	6	8	8	$1.8	1%	11%	11%	19%	11,300

* CCs modeled as single trains, with duct burners modeled separately (with operations tied to parent CC) and not able to provide AS

** Quick start units are given a non-standardized ramp rate based on past performance

*** Online non-spin capabilities not shown here because capabilities vary with each unit's hourly output vs. HSL (and ramp rates)

Appendix
Provision of FAS Products

Product	Eligible Resources
Regulation—4 products	Same as under CAS
FFR1 (59.8 Hz, limited duration)	Batteries, flywheels, loads with short duration
FFR2 (59.7 Hz, longer duration)	Existing & new load resources
PFR	Same as those providing Gen RRS under CAS plus wind, batteries, and controllable loads
CRS1 (dispatchable 10-min)	Any qualified online/offline gen, dispatchable load
CRS2 (manual 10-min)	Existing & new load resources
SRS1 (dispatchable 30-min)	Any qualified online/offline gen, dispatchable load
SRS2 (manual 30-min)	Existing & new load resources

Appendix
Current Trends Scenario

Assumptions are based on the LTSA 2014 Scenarios

- Conditions existing today will generally continue into the future
- ERCOT's base case load forecast (as of Dec 2013) with the addition of small amounts LNG
- Natural gas prices are $4.35/MMBtu in 2016 and $5.93/MMBtu in 2024
- No expected changes to environmental regulations, except in the Stringent Environmental case ($45/MMBtu CO_2 price)

Changes from the LTSA

- Wind and solar additions adjusted based on current ERCOT queue, with interconnection agreement signed and financing secured
- Generic CCs and CTs added to the 2024 to ensure adequate and equal reserve margins between cases

Appendix
Acronym Definitions

AS – Ancillary Services

CAES– Compressed-Air Energy Storage

CAS – Current Ancillary Services

CBA– Cost-Benefit Analysis

CC – Combined Cycle

CRS – Contingency Reserve Service

DA– Day-Ahead

DG – Distributed Generation

DR – Demand Response

FAS– Future Ancillary Services

FFR– Fast Frequency Response

FRRS– Fast-Responding Regulation Svc

LTSA– Long-Term System Assessment

LR– Load Resources

NSRS– Non-Spin Reserve Service

NT – New Technology

OCS– Opportunity Cost Savings

PCS– Production Cost Savings

PFR – Primary Frequency Response

PLEXOS– Integrated Energy Model

P & Q– Price and Quantity

RRS– Responsive Reserve Service

RT– Real-Time

SCED– Security Constrained Economic Dispatch

SE – Stringent Environmental

SRS– Supplemental Reserve Service