2020 EORM Study
SAWG Presentation 10/26/2020

Prepared for Electric Reliability Council of Texas

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Contents

- Overview
- Scenarios
- Renewable Accounting
- Current Results
- Storage Modeling

Study Context: an Evolving Load and Resource Mix

	2018 Study Quantity (2022 Study Year) *(MW)*	2020 Study Quantity (2024 Study Year) *(MW)*	Differences *(MW)*	Comments
Peak Load	**79,027**	**82,982**	**3,955**	*2.5% Annualized Load Growth, larger system corresponds to fewer reliability issues all else equal*
Demand Response				
LRs serving RRS	1,119	1,172	53	
10-Minute ERS	140	76	-64	
30-Minute ERS	632	692	60	
TDSP Curtailment Programs	282	262	-20	
Supply	**85,595**	**93,979**	**8,384**	
Conventional Generation	72,441	68,395	-4,046	*CT capacity treated as variable given range of RMs*
Hydro	466	474	8	
Wind	6,331	9,137	2,806	*+5.55 GW nameplate, adjusting the 2018 Study Year for current accounting value the delta is only +721 MW;*
Solar	2,708	12,161	9,453	*+12.4 GW nameplate, adjusting the 2018 Study Year for current accounting value the delta is +36 MW;*
Storage	0	0*	0	
PUNs	3,259	2,962	-297	
Capacity of DC Ties	389	850	461	
Reserve Margin	11.37%	16.34%	4.97%	Treated as *variable* to determine MERM and EORM

*1,103 MW of nameplate capacity of storage is included in the 2024 study but given a 0% capacity credit in the reserve margin calculation

Note: Energy Efficiency Programs are already removed from the modeled peak load and are not represented in the modeled load reduction programs (2,884 MW in 2024 Study Year)

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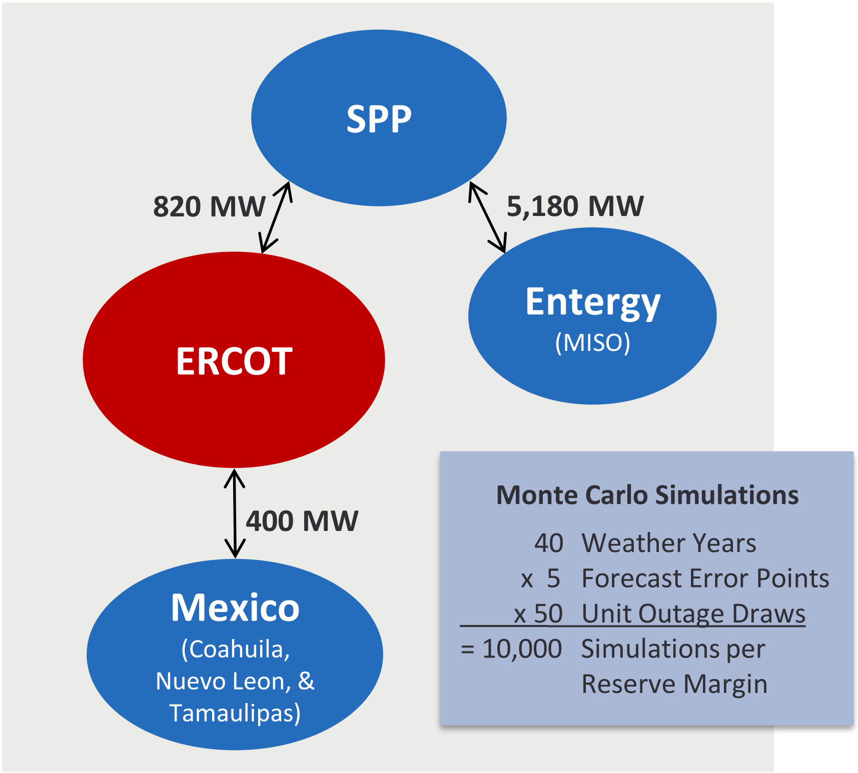
Overview

- Strategic Energy and Risk Valuation Model (SERVM) is a probabilistic multi-area reliability and economic modeling tool, representing:
  - Demand in ERCOT and external regions
  - Generation with randomized outages
  - Demand response of several types with differing availability and emergency or economic triggers
  - Emergency procedures that ERCOT triggers in shortage conditions
- Monte Carlo simulation of 20,000 different annual hourly-sequential simulations at each reserve margin
- Primary outputs are reported at each reserve margin, including:
  - Reliability metrics such as LOLE
  - Economic costs such as production costs, DR curtailment costs, and emergency intervention costs
  - Market results including prices and energy margins

Modeled Interconnection Topology



Sources:
http://www.ercot.com/content/wcm/key_documents_lists/90055/ERCOT_DC_Tie_Operations_Document.docx

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Case Scenarios

Scenario Name	Base Case Assumption	Alternate Scenario Assumption	Expected EORM Impact
High Renewables Penetration	Only include Tier 1 wind and solar from CDR	Include some of the wind and solar from the interconnection queue that has not met all requirements for CDR (15 GW of new solar, 5 GW of new wind)	Downward pressure on prices and therefore lower EORM
Storage Reference Resource	Use Gas CT as reference resource	Use storage as reference resource. Simulate at high renewable penetration	
EFOR	Last 3 years used to populate outage rates for all units	Use class average EFORs from 2018 study	2018 outage rates will produce a lower EORM

Case Sensitivities

We will also run several non-model sensitivities to test the impact if key uncertainties on the economic and optimal reserve margins.

Sensitivity	Base Case Assumption	Sensitivity Range
Gross Cone/ATWACC	General merchant values	-10%/+25%
VOLL	$9,000/MWh	$5,000-$30,000/MWh
Weather Weights of Load Years	Equal weight to all 40 weather years	Only use last 15 years of weather history
Forward Period for Capacity Decisions	4 years	0 years to 4 years
Economic Forecast Uncertainty	4% under-forecast to 4% over-forecast	Change weightings of forecast scenarios

Load Modeling
Peak Load and Neighbor Diversity

Summer Peak Loads and Diversity

Loads as used in Reserve Margin Accounting

		ERCOT	Entergy	SPP	Mexico	Total
Summer Peak Load Forecast						
Non-Coincident	*(MW)*	82,982	33,658	54,012	12,950	183,601
Coincident	*(MW)*	80,572	32,618	52,893	12,651	178,734
At ERCOT Peak	*(MW)*	82,982	30,809	48,605	12,872	175,268
Load Diversity						
At Coincident Peak	*(%)*	2.99%	3.19%	2.11%	2.36%	2.72%
At ERCOT Peak	*(%)*	0.00%	9.25%	11.12%	0.61%	4.75%
Reserve Margin at Criterion						
At Non-Coincident Peak	*(%)*	n/a	16.80%	12.00%	15.00%	n/a
At ERCOT Peak	*(%)*	n/a	27.60%	24.46%	15.00%	n/a

Sources and Notes:

ERCOT load shapes for 2024 provided by ERCOT staff, table is consistent with peak loads used in reserve margin accounting (excluding any PRD or LR gross-up but including TDSP Energy Efficiency Programs.)

SPP and Entergy load shapes developed based on statistical relationships from 5 years of load data for Entergy and 6 years of load data for SPP (from FERC Form 714) and 40 years of weather data (from NOAA).

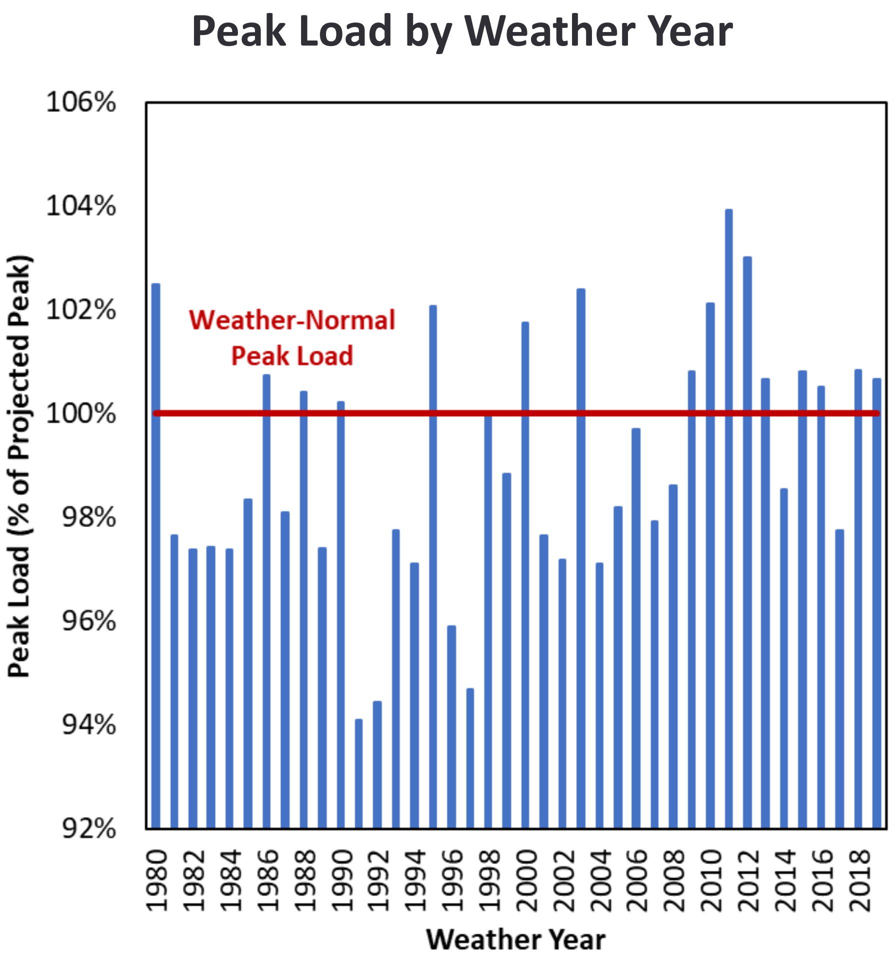
SPP wind capacity credit and reserve margin at non-coincident peak were derived from: https://www.spp.org/documents/58198/2017%20spp%20lole%20study%20report.pdf

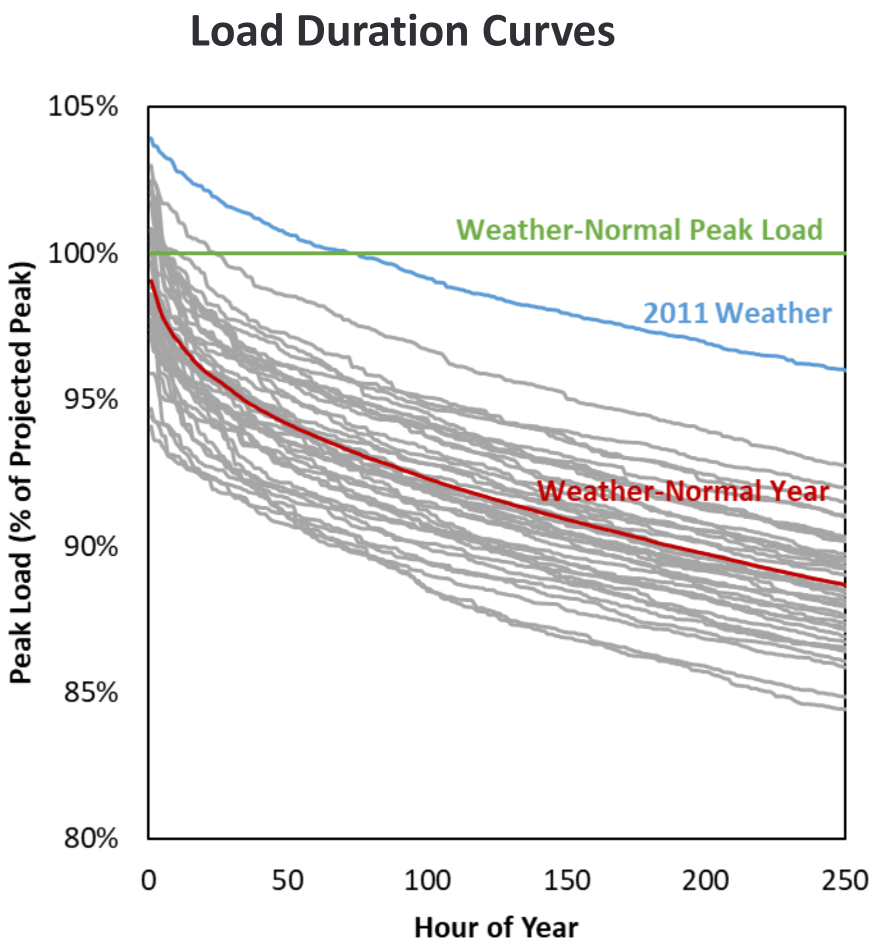
Entergy reserve margin at non-coincident peak was derived from: https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf

Mexico load shape and forecast data were unavailable, assumed a representative 15% reserve margin above generation fleet from Ventyx and a load shape identical to ERCOT.

SPP Peak Demand from the 2019 NERC LTRA https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

Load Modeling
Load Shapes and Weather Years





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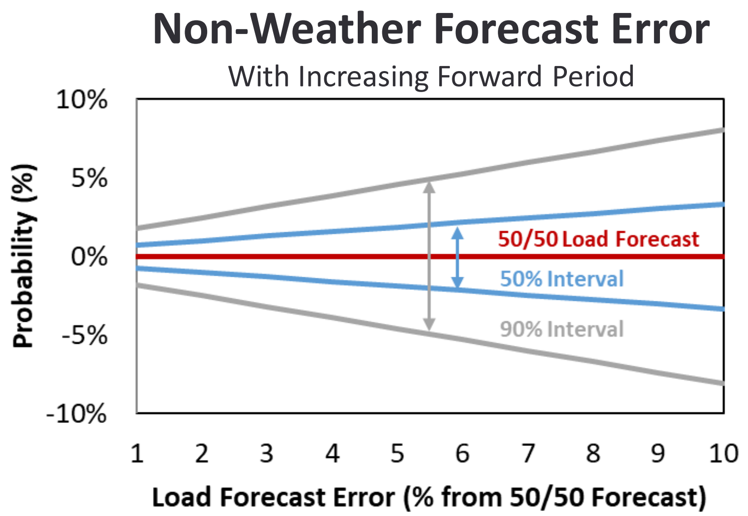
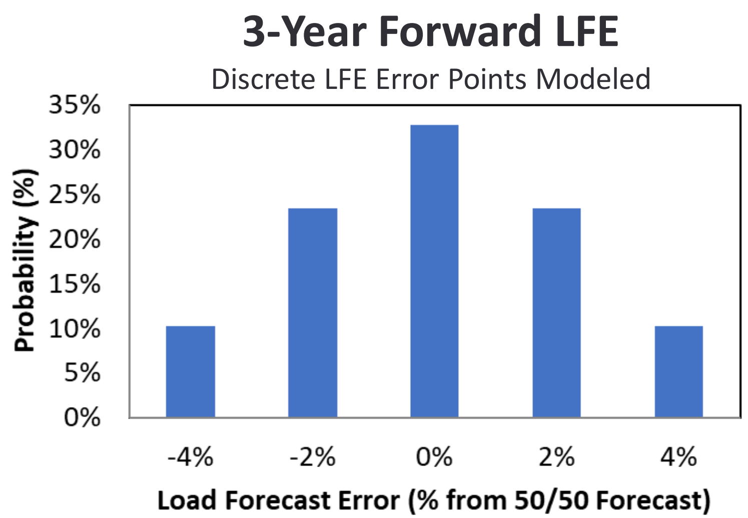
Load Modeling
Load Forecast Uncertainty and Forward Period

- Non-weather load forecast error increases with forward period:
  - Assume electric load growth increases at 40% the rate of GDP growth (approximately consistent with ERCOT forecast and national average)
  - Economic forecast uncertainty increases with forward period, consistent with uncertainty distribution around 28 years of CBO economic forecasts
- Modeling approach:
  - Assume resource decisions and reserve margin must be "locked in" 4 years forward, so realized forecast error is larger than if more short-term options were available
  - Sensitivity analysis examining impact of forward periods ranging from 1 to 5 years forward





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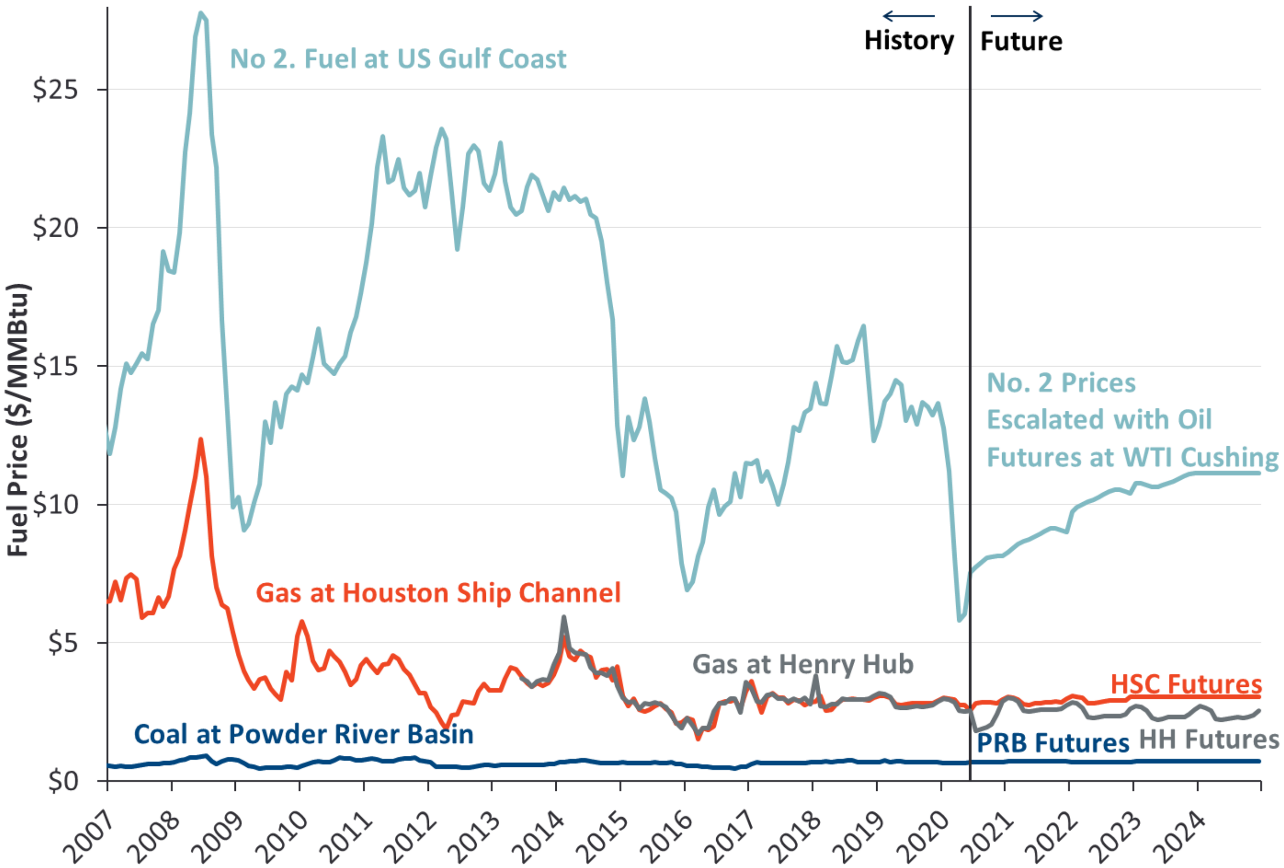
Generation Resources
Fuel Prices



ERCOT 2024 Fuel Forecast

Coal Fuel Price ($/MMBtu)	Gas Fuel Price ($/MMBtu)	Diesel Fuel Price ($/MMBtu)
1.65	2.96	11.14

Sources and Notes:

Historical and futures prices from Bloomberg, SNL Energy, and EIA.
Locational basis estimated using Ventyx delivered fuel price estimates in each region, escalated with inflation.
Diesel prices only apply for units in SPP, Mexico, and Entergy.

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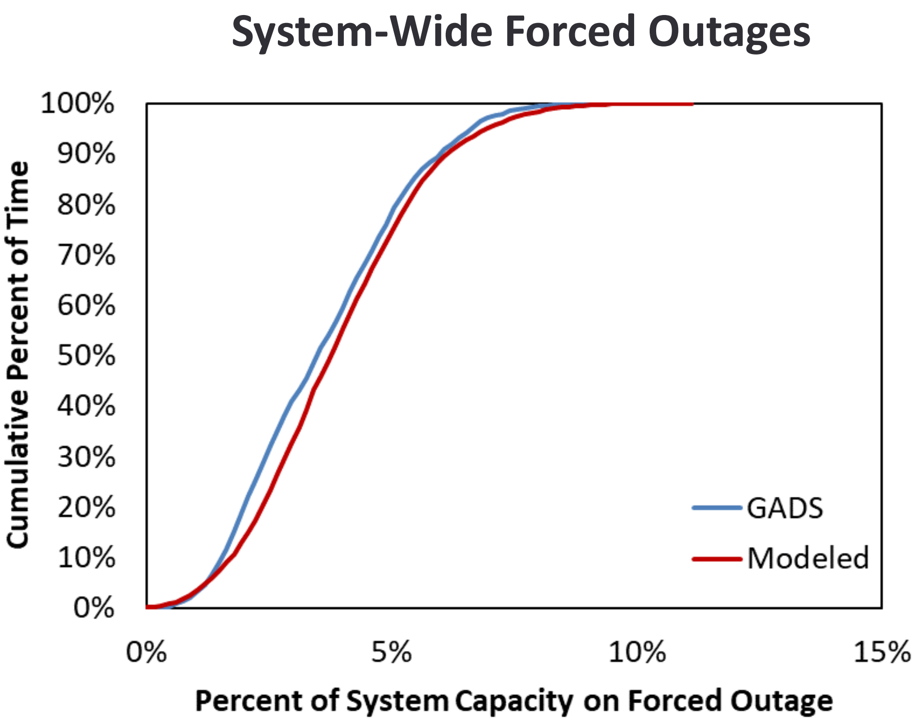
Generation Resources
Conventional Generation Outages

- Model individual unit outages stochastically, including:
  - **Full Outages**: mean time to fail, mean time to repair
  - **Partial Outages**: derate percentage, mean time to fail, mean time to repair
  - **Startup Failure**: probability of failure during startup
  - **Maintenance Outages**: average outage rate with random occurrence and limited scheduling flexibility
  - **Planned Outages**: average outage rate with known occurrence and substantial scheduling flexibility in fleet
- Distributions of outage parameters created from:
  - Historical GADS data provided by ERCOT for most of the fleet
  - Units without historical GADS data are linked to units with data by unit class and size
  - Calibrated to historical summer performance



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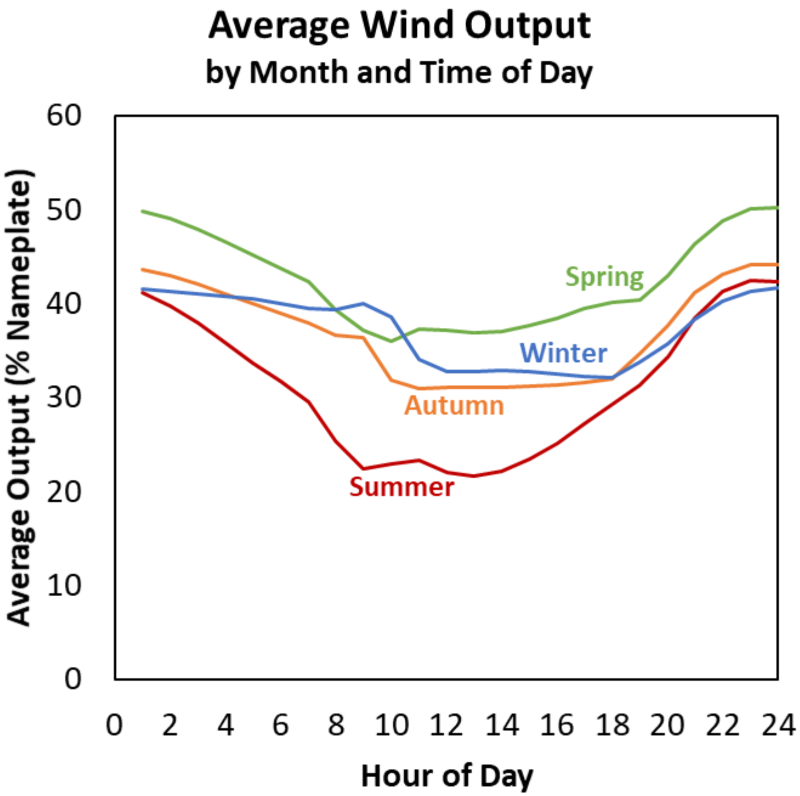
Generation Resources
Wind and Solar

Wind

- 37,396 MW nameplate for 2024
- 40 years of hourly local wind shapes provided by ERCOT from AWS True Power
  - Aggregated operational local curves to system-wide
- 36.4% average capacity factor
- 29% panhandle wind/ 63% coastal wind/ 16% other wind capacity credit (consistent with CDR)

Solar Photovoltaic

- 16,001 MW nameplate for 2024
- 40 years of hourly solar county-specific shapes provided by ERCOT
  - Aggregated operational local curves to system-wide
- 27.3% average capacity factor
- 76% capacity credit (consistent with CDR)



Sources and Notes:
Average of 40 years' hourly wind profiles provided by ERCOT

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Renewable Accounting

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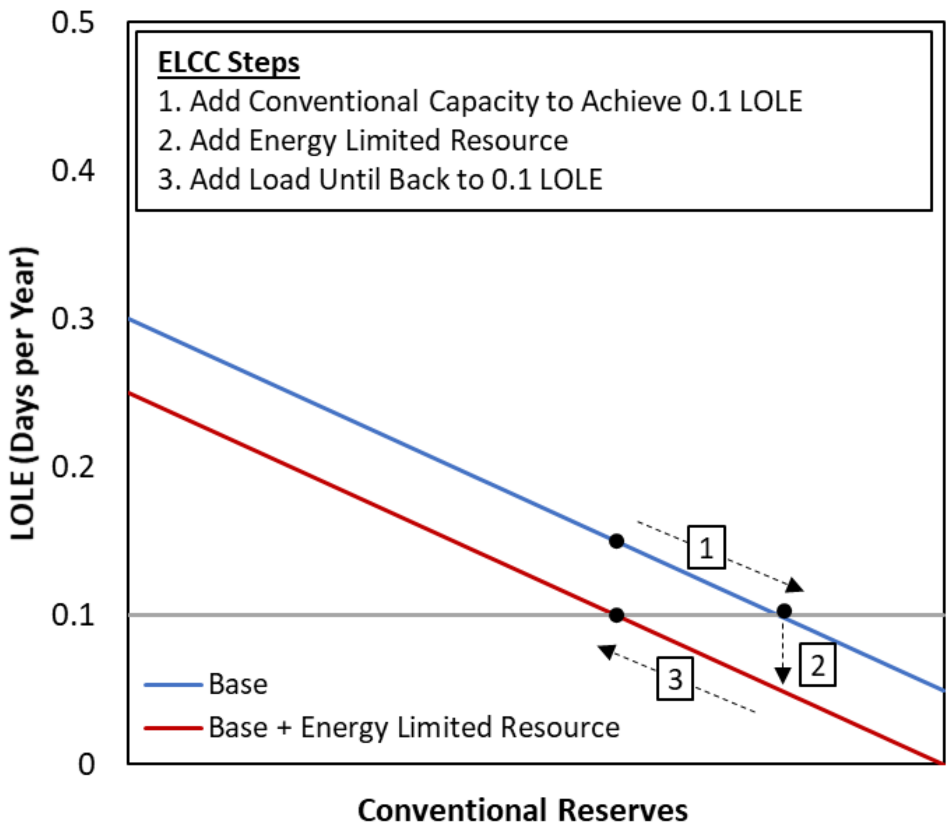
ELCC Methodology



- Increasing renewable penetration results in declining ELCCs
- ELCC is intended to normalize for reliability contributions of non-dispatchable or energy limited resources and maintain a static reserve margin

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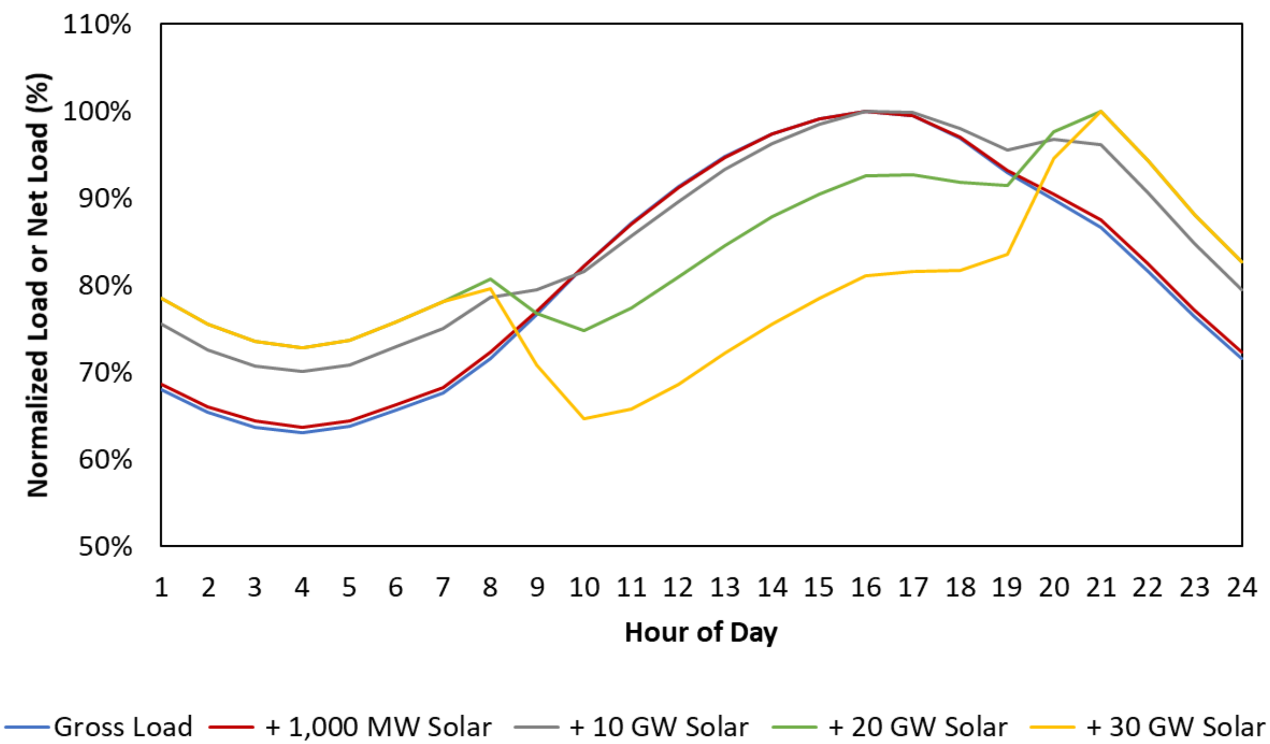
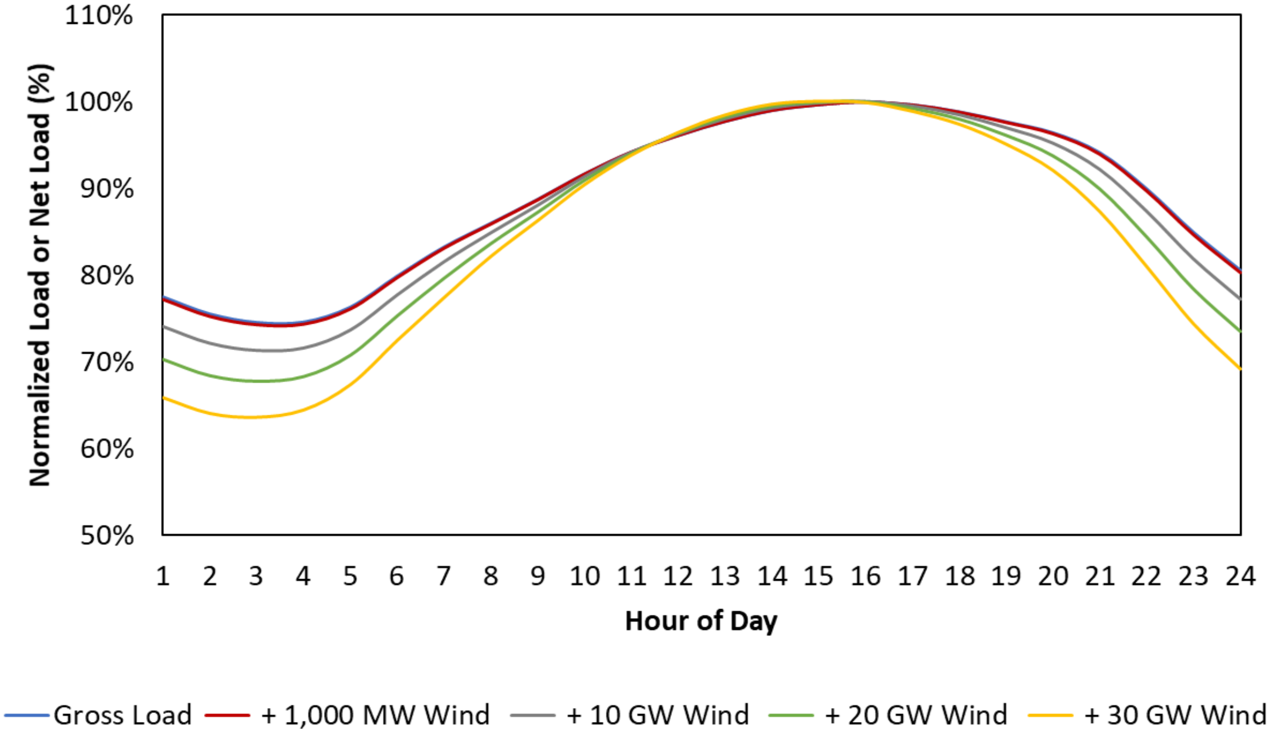
Generation Resources
Solar



Solar Penetration (MW)	Solar Output in Top 100 Highest Net Load Hours (MW)	Normalized Solar Output (%)
1,000	809	80.9%
10,000	7,841	78.4%
20,000	746	3.7%
30,000	202	0.7%

- Solar ELCC declines due to shifting net load
- Average shapes when daily peak load is greater than 75,000 MW

Generation Resources
Wind



Wind Penetration (MW)	Wind Output in Top 100 Highest Net Load Hours (MW)	Normalized Wind Output (%)
1,000	204	20.4%
10,000	1,518	15.2%
20,000	2,108	10.5%
30,000	2,420	8.1%

- Wind ELCC declines due to correlated low wind output

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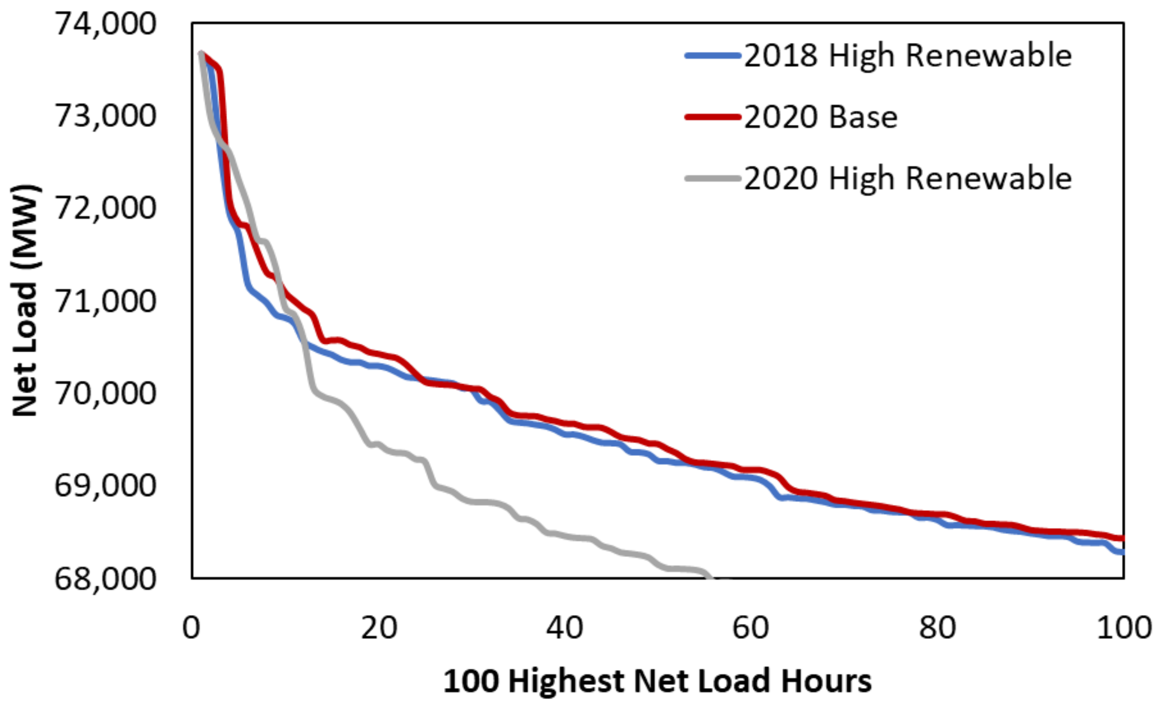
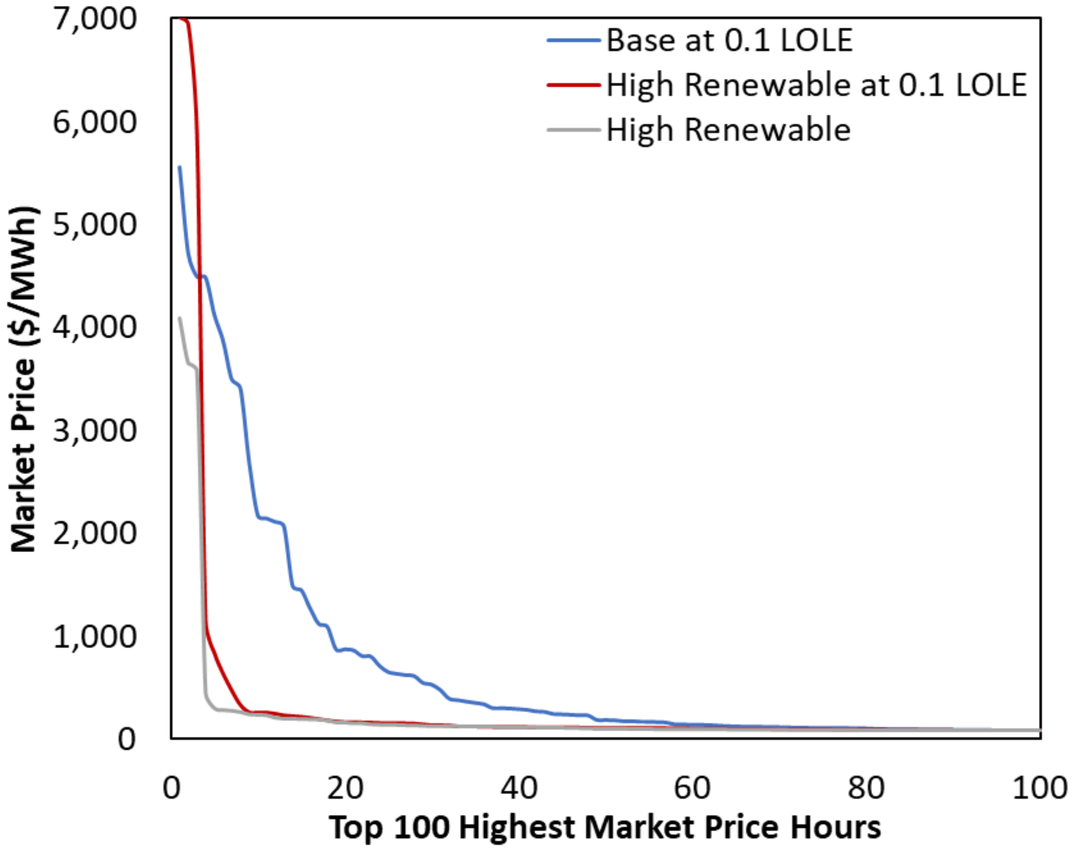
Generation Resources
Wind and Solar



- 2020 Base Case is comparable to 2018 High Renewable Scenario
- 2020 High Renewable has steeper net load shape resulting in lower MERM

All net load shapes were normalized to the same 2020 base peak.

Generation Resources
Wind and Solar



- Steeper net load and market price duration curve will produce the same reliability at the same reserve margin, but lower frequency of high-priced hours

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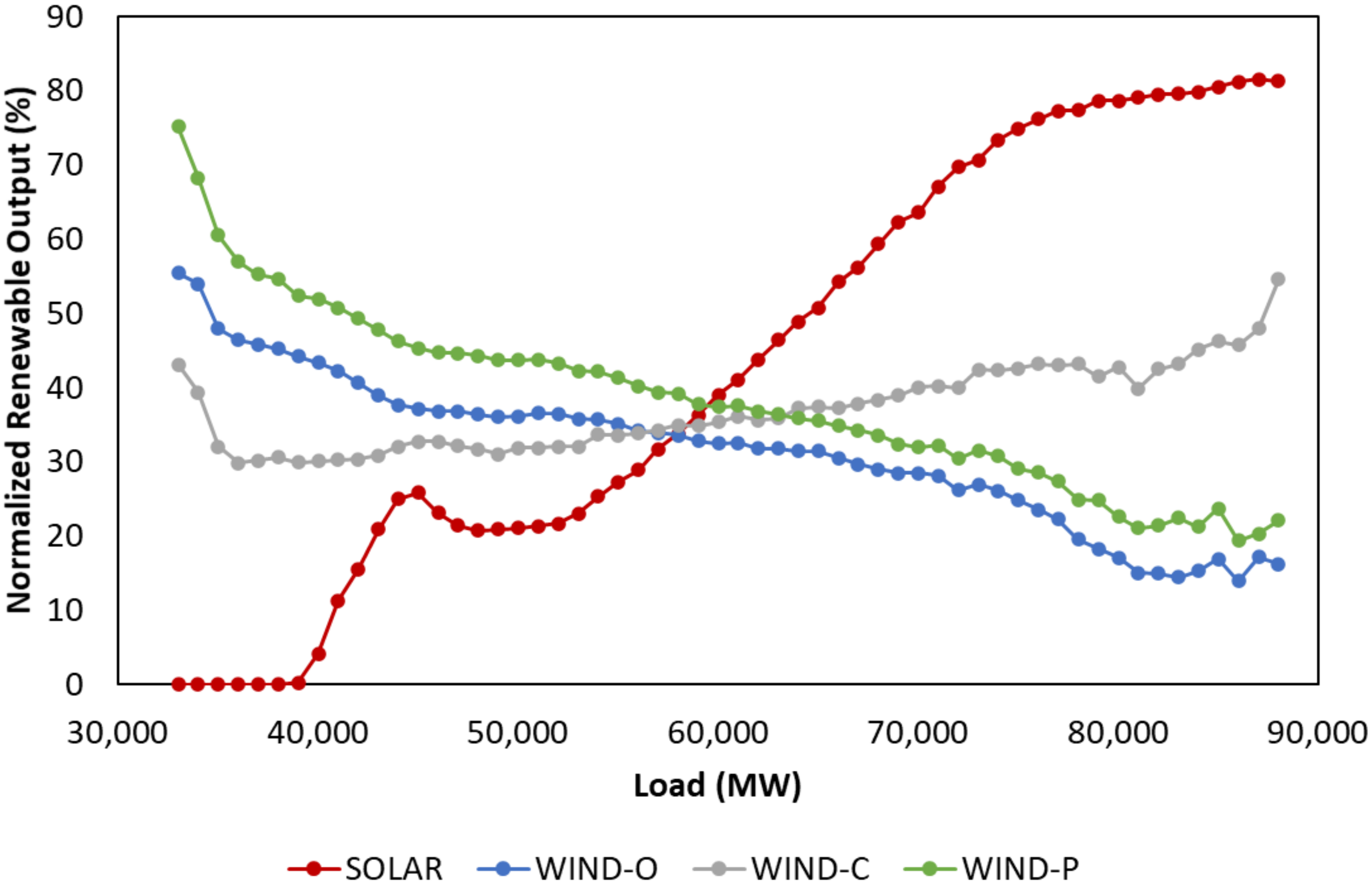
Generation Resources
Wind and Solar



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Generation Resources
Marginal Resource Technology

CT Performance Characteristics

		Simple Cycle
Plant Configuration		
Turbine		GE 7HA.02
Configuration		1 x 0
Heat Rate (HHV)		
Base Load		
Non-Summer	(Btu/kWh)	9,138
Summer	(Btu/kWh)	9,274
Installed Capacity		
Base Load		
Non-Summer	(MW)	371
Summer	(MW)	352
Gross CONE	($/kW-yr)	93.5

Note: Based on ambient conditions of 92°F Max. Summer (55.5% Humidity) and 59°F Non-Summer.

Battery Storage Performance Characteristics

		Battery Storage
Installed Capacity		
Base Load		
Non-Summer	(MW)	100
Summer	(MW)	100
Storage Capability	(Hours)	4
Gross CONE	($/kW-yr)	147

Demand-Side Resources
Cost and Modeling of Demand Resources

Resource Type	Quantity *(MW)*	Modeling Approach	Marginal Curtailment Cost	Adjustments to ERCOT Load Shapes	Reserve Margin Accounting
TDSP Programs					
Energy Efficiency	2,884	Not explicitly modeled	n/a	None (ERCOT load shapes already reduced for TDSP EE Programs)	Load reduction
Load Management	262	Emergency trigger at EEA Level 2	$2,469	None (ERCOT load shapes estimated assuming no LM curtailments)	Load reduction
Emergency Response Services (ERS)					
30-Minute ERS	691	Emergency trigger at EEA Level 1	$1,372	None (ERCOT load shapes estimated assuming no ERS curtailments)	Load reduction
10-Minute ERS	76	Emergency trigger at EEA Level 2	$2,469		Load reduction
Load Resources (LRs)					
Non-Controllable LRs	1,172	Economically dispatch for RRS (most hours) or energy (few peak hours). Emergency deployment at EEA Level 2	$2,469	None (ERCOT load shapes estimated assuming negligible LR curtailments)	Load reduction
Controllable LR	0	Currently no controllable LRs modeled in ERCOT	n/a		
Voluntary Self-Curtailment					
4 CP Reductions	1,700	Response modeled to match load gross up. Same response modeled in all reserve margins.	n/a	Load grossed up based on observed performance.	None. Already excluded from reported peak load
Price-Responsive Demand	Variable	Economic self-curtailment, but with uncertain availability. Will vary by reserve margin.	$500 - $9,000 /MWh	Load grossed up based on observed performance.	None. Already excluded from reported peak load

Note: The marginal cost of the emergency DR is given by the prices on the dark blue curve corresponding to the reserve levels at the EEAs at which emergency DR is triggered. That assumes the blue curve reflects actual costs (with the red curve shifted right to boost resource adequacy) and that actions are taken at an economically rational point. Prices are set according to the red curve. We observed that modeled prices will tend to cluster around the EEA trigger points on the red curve since a range of net loads and corresponding emergency DR deployments will stay on that shelf.

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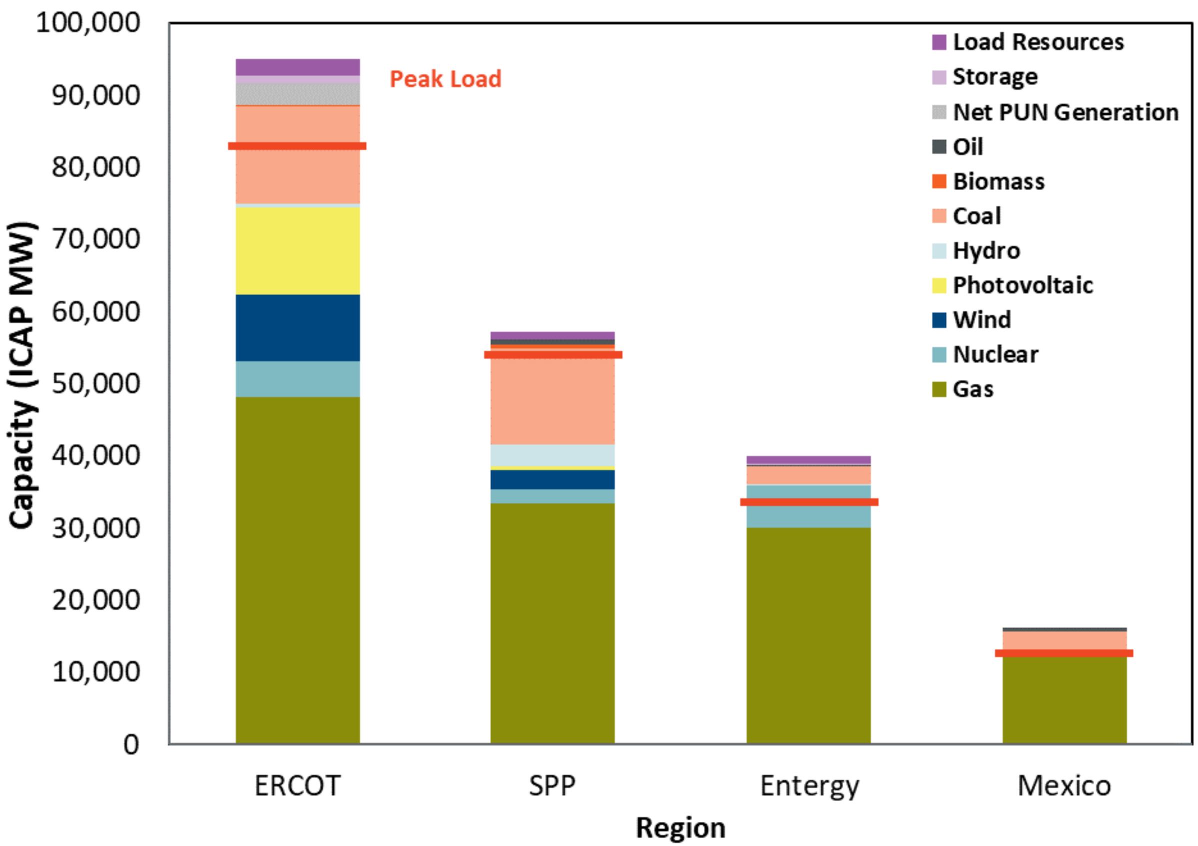
System Summary
Resource Mix



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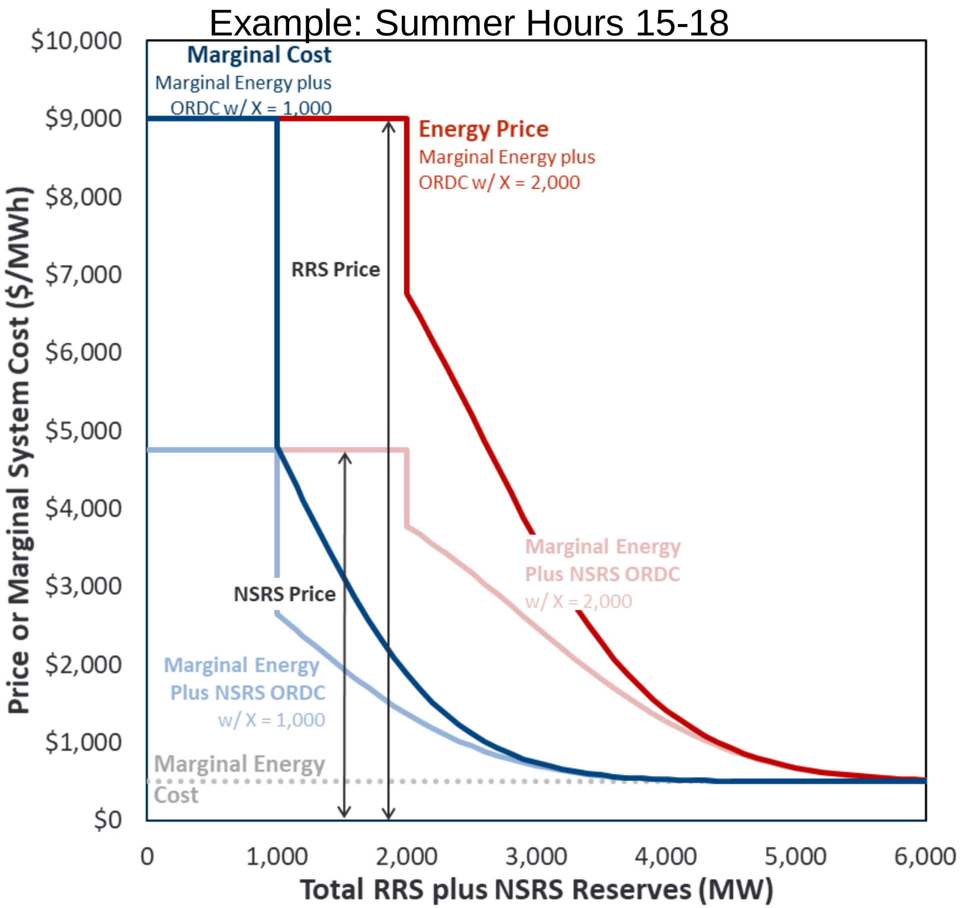
Scarcity Conditions
Operating Reserve Demand Curve

Implementation

- All ORDC curves implemented (4 seasons, 6 times of day, 2 reserve types)
- Price-setting based on curve where X = 2,000 MW; marginal system cost assumes load shed at X = 1,000 MW
- Simplifications:
  - Assume PRC, Spin, and ORDC x-axis are all self-consistent
  - Do not scale ORDC curves each hour, instead calculate as if marginal energy were fixed at the emergency gen dispatch price of $1,372/MWh
  - Assume non-spin is depleted before spin (i.e. 1-to-1 correspondence between the x-axes of Spin and Non-Spin ORDC curves)
  - Day-ahead commitment of spin is equal to the minimum of: (a) ERCOT requirement, and (b) reasonable min ORDC spin price of $3/MWh (i.e. allow self-commitment to prevent very high prices during long conditions)

Operating Reserve Demand Curves



Sources and Notes:
ERCOT ORDC Calculation Methodology Paper.

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Current Results

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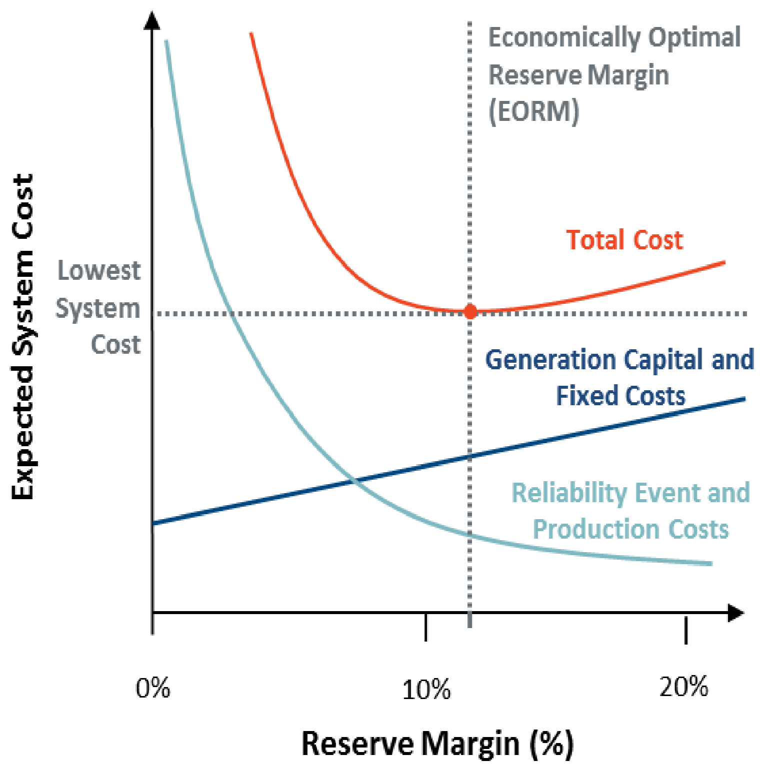
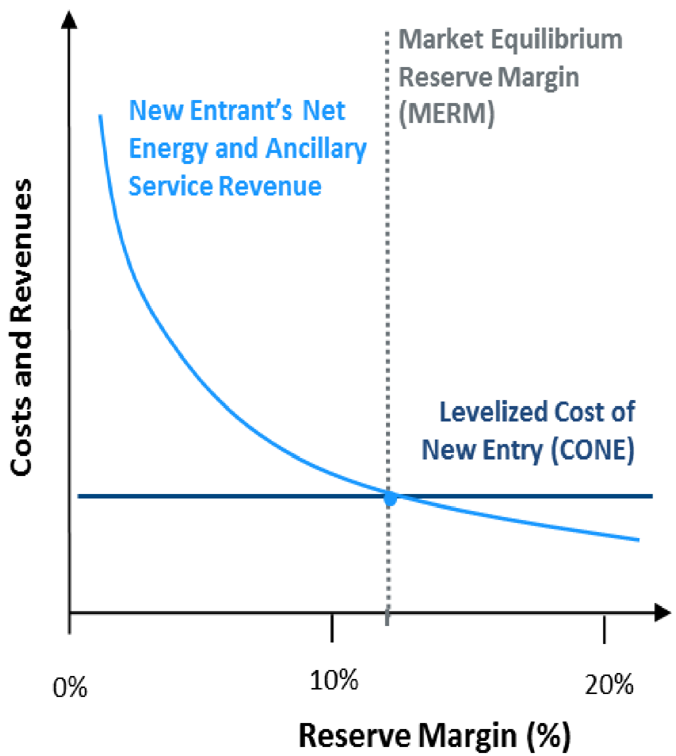
EORM and MERM





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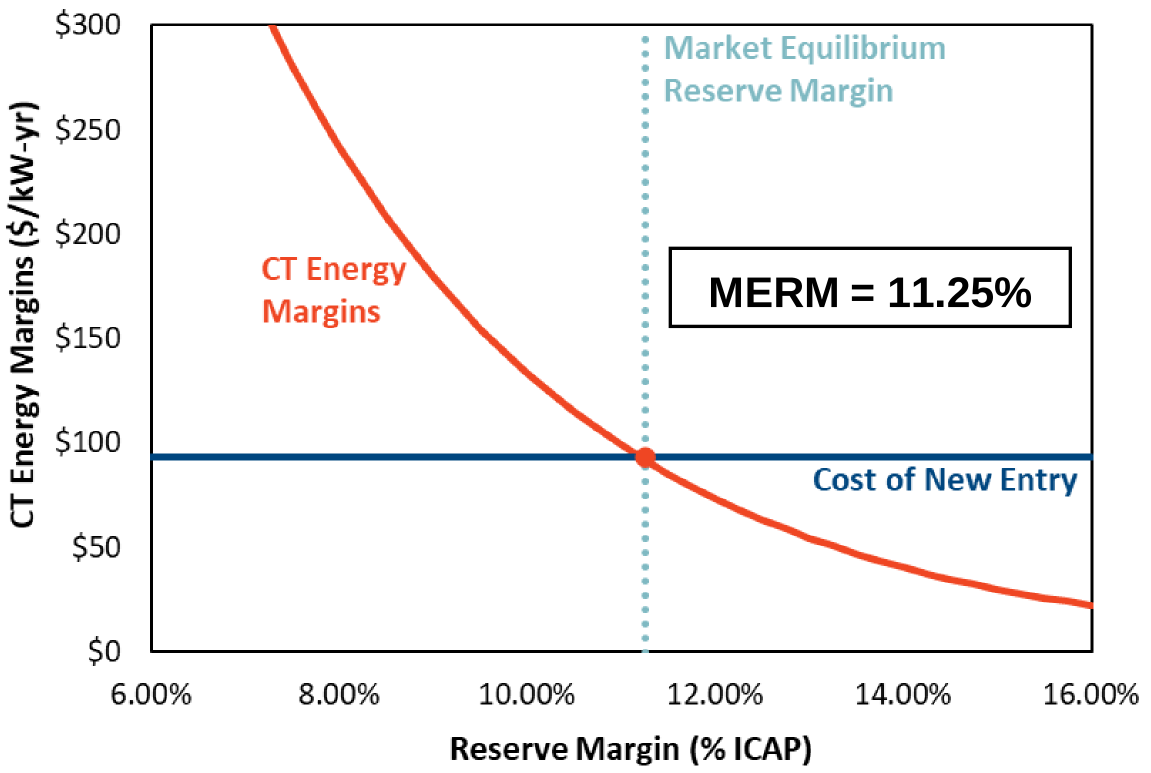
Market Equilibrium Reserve Margin (MERM)



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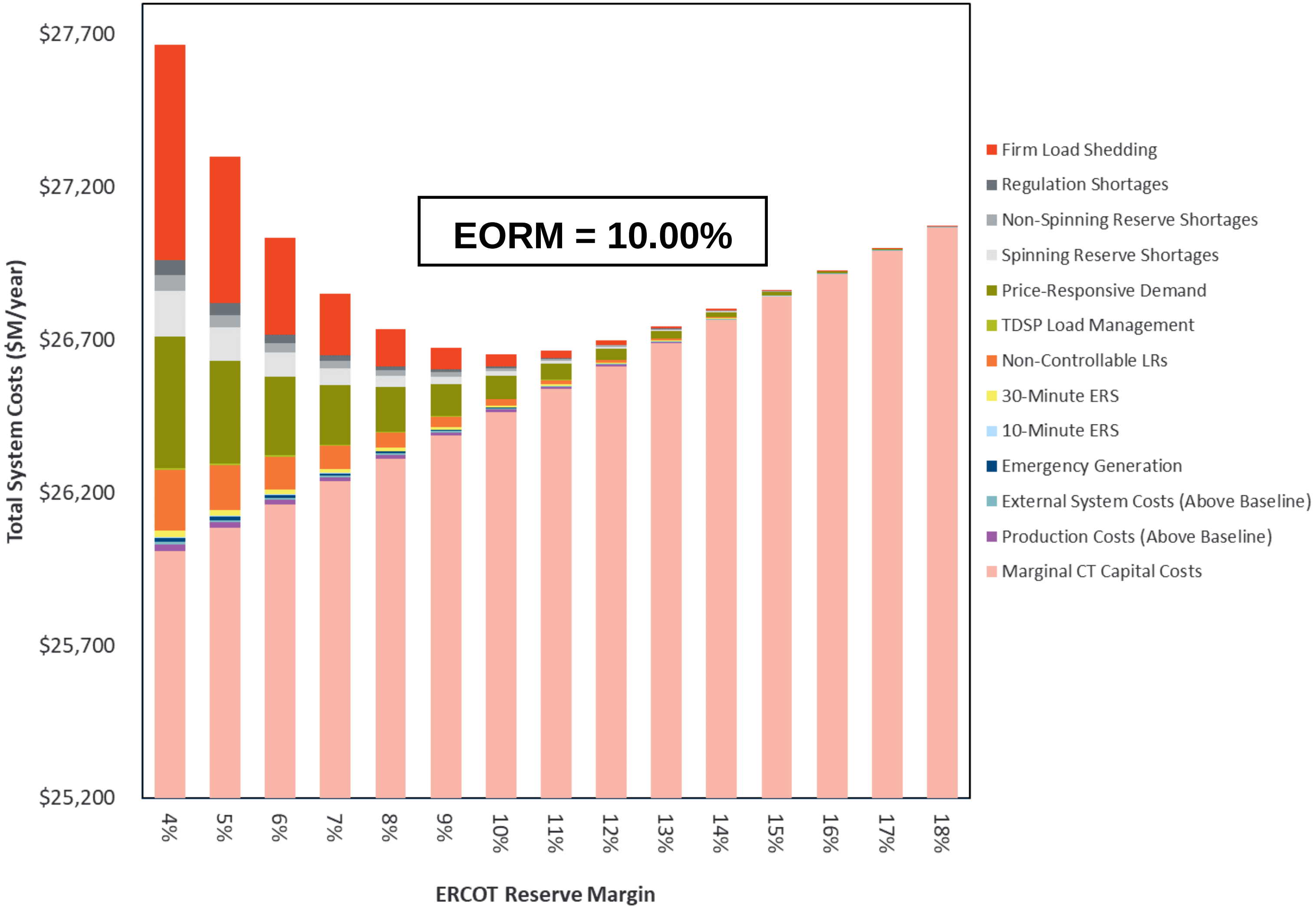
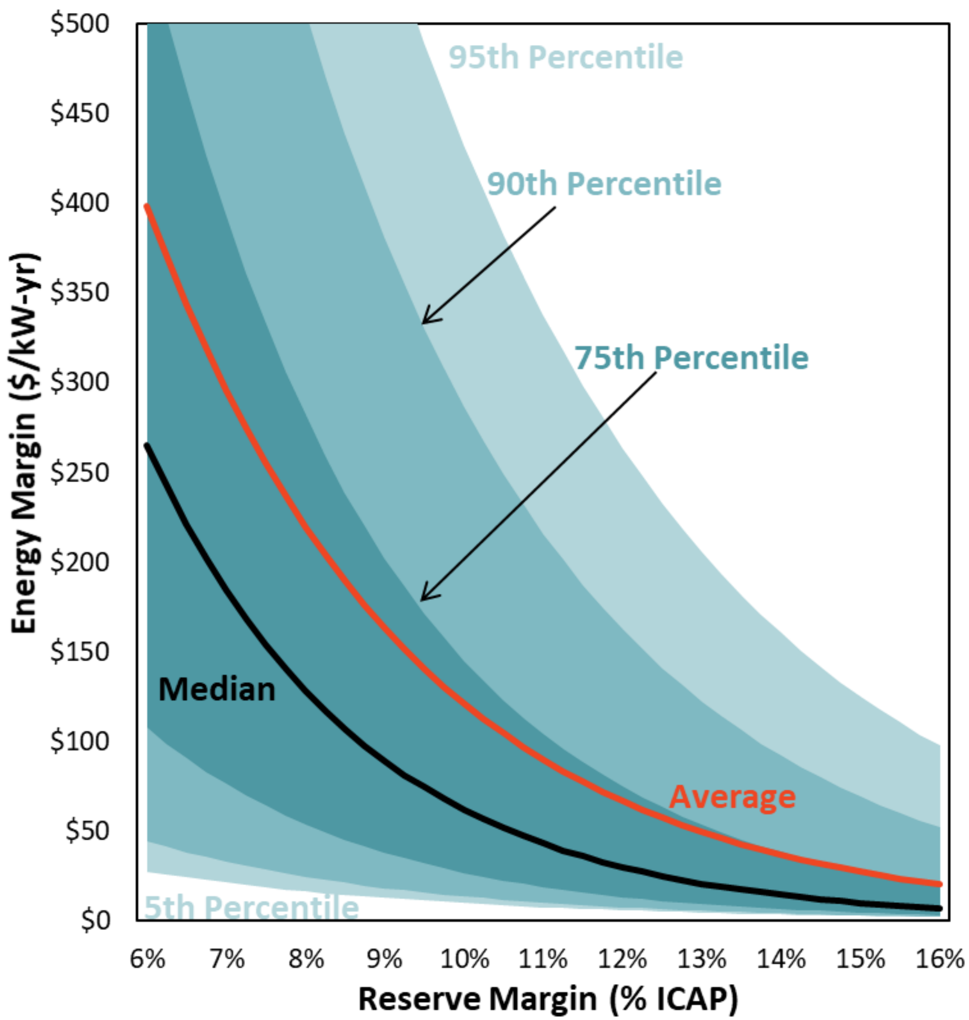
EORM Curve



Total System Costs ($M/year)
$27,700
$27,200
$26,700
$26,200
$25,700
$25,200
EORM = 10.00%
4%
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
16%
17%
18%
ERCOT Reserve Margin
Firm Load Shedding
Regulation Shortages
Non-Spinning Reserve Shortages
Spinning Reserve Shortages
Price-Responsive Demand
TDSP Load Management
Non-Controllable LRs
30-Minute ERS
10-Minute ERS
Emergency Generation
External System Costs (Above Baseline)
Production Costs (Above Baseline)
Marginal CT Capital Costs

Percentile Distribution of Energy Price Forecast by Reserve Margin



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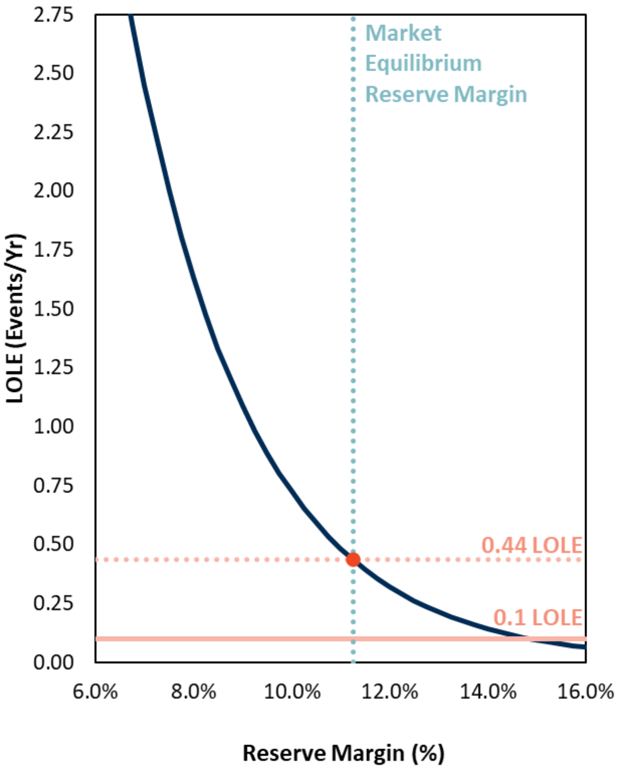
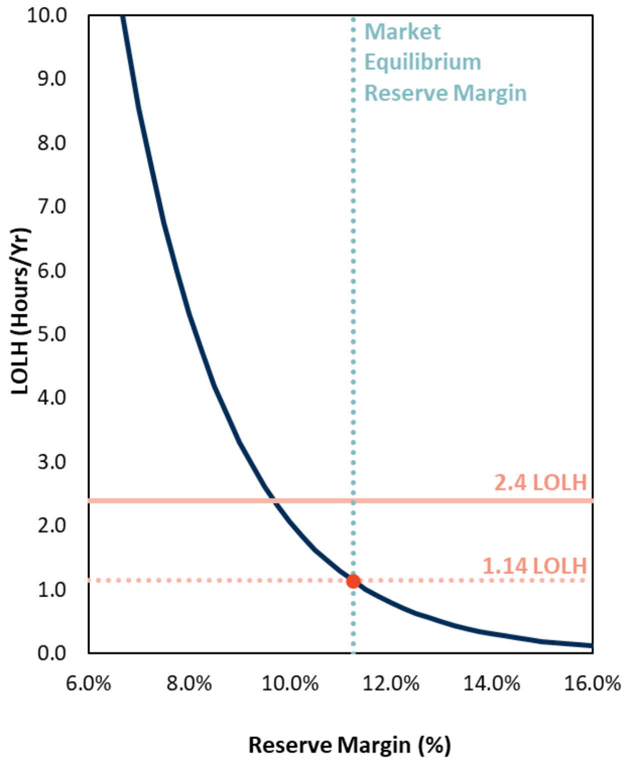
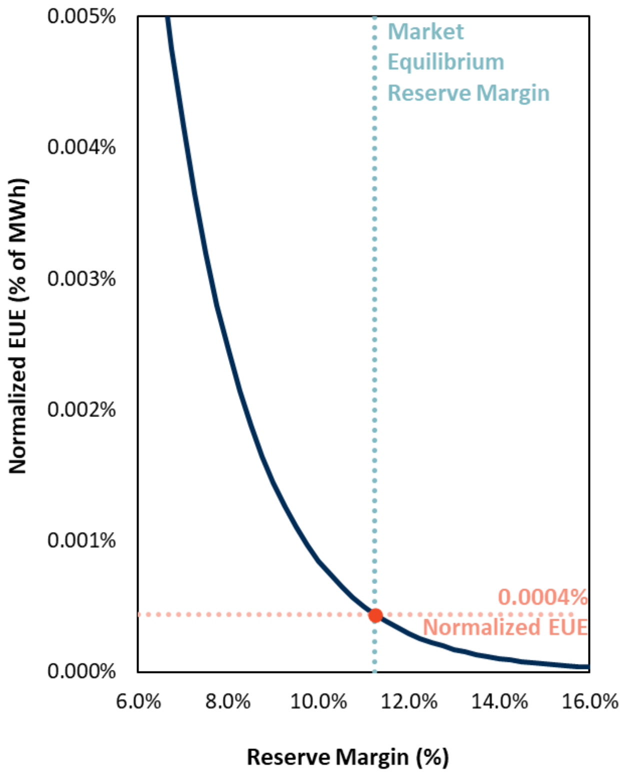
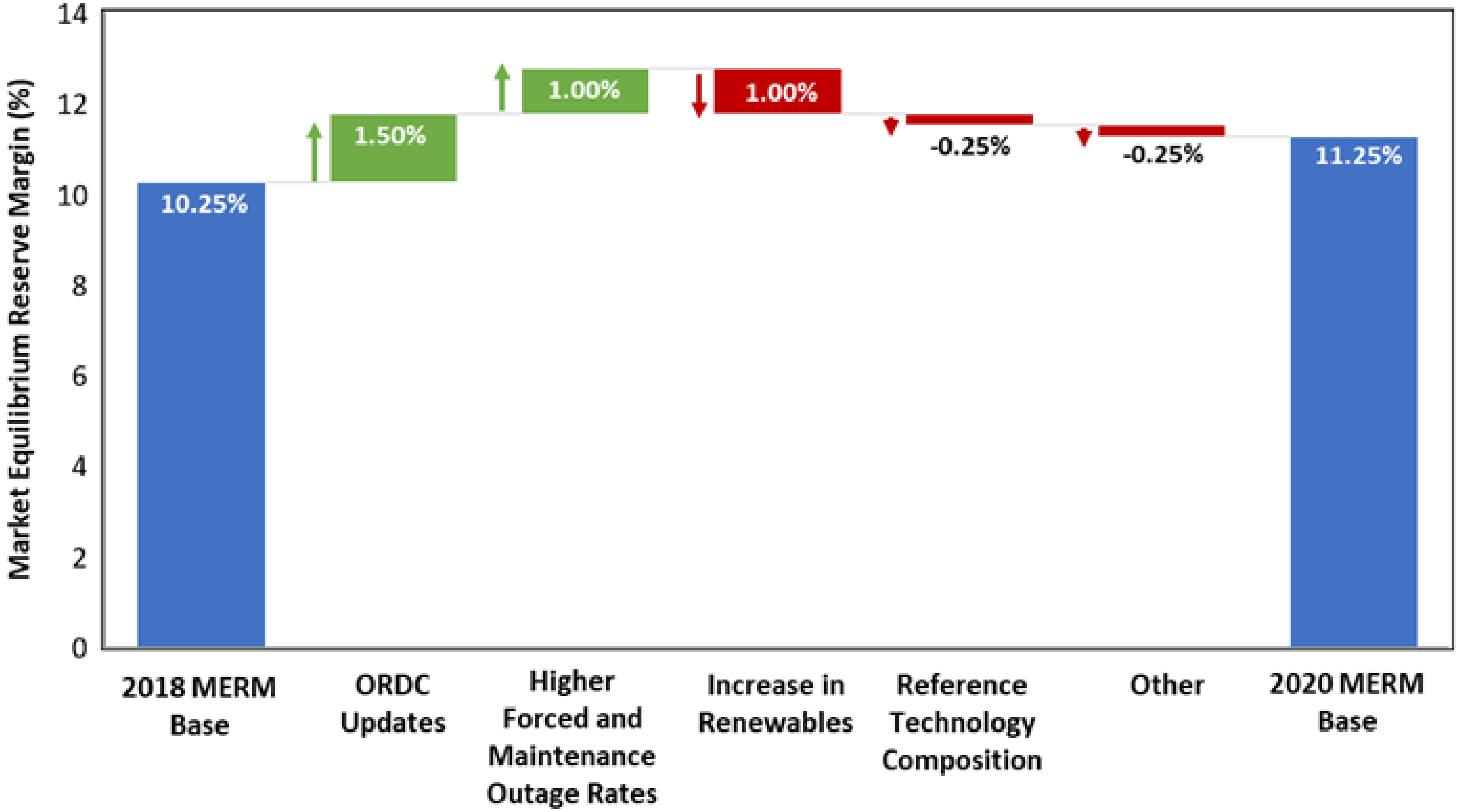
Reliability Metrics







Base MERM Changes from 2018 to 2020 Study



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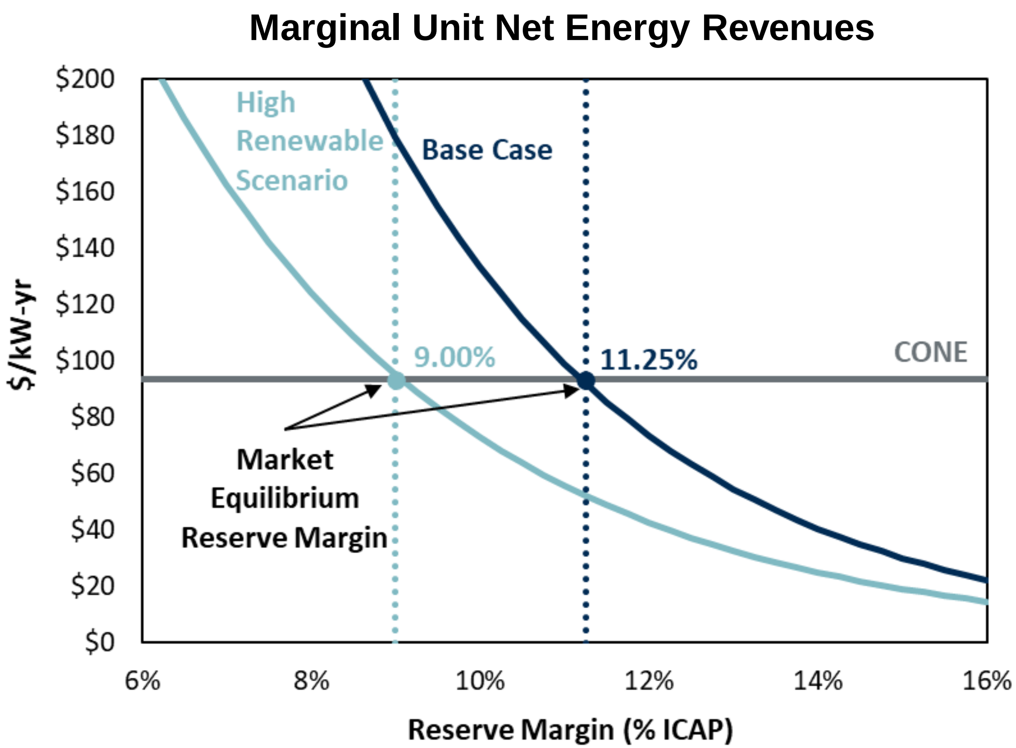
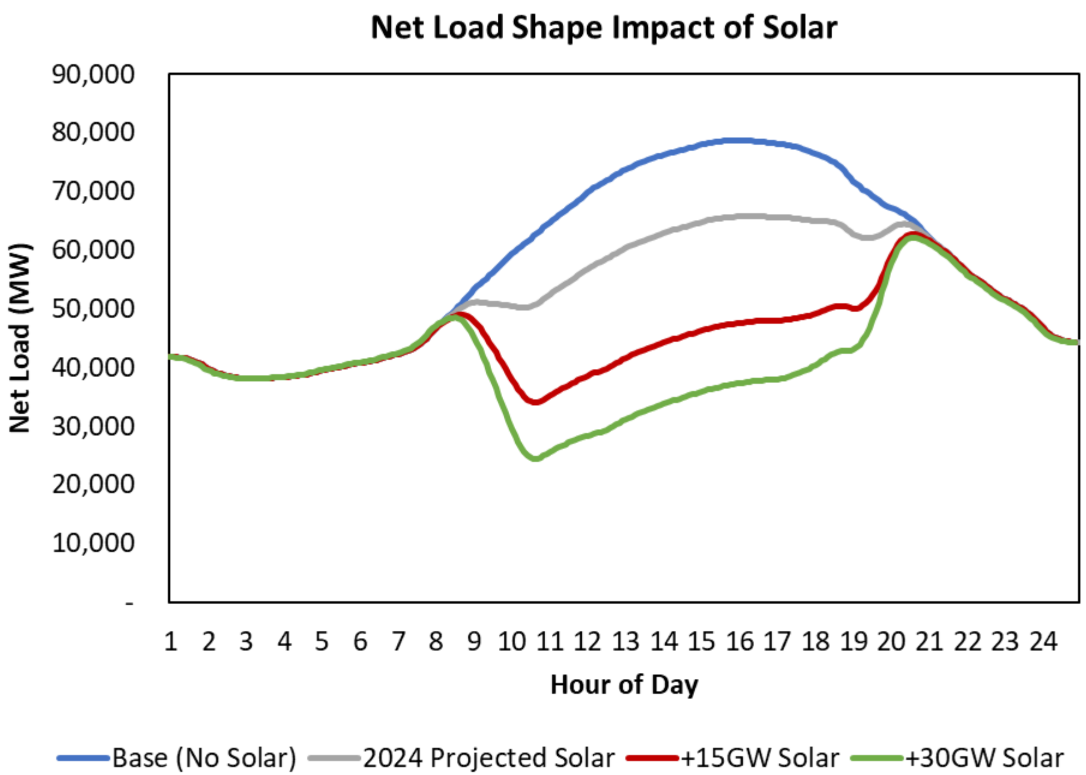
High Renewable Sensitivity



Storage Scenario

Storage Scenario

- **Current 2024 net load shape is too flat to support much storage as capacity resources**
  - Solar additions up to 2024 have flattened the net load shape
  - Future additions will steepen the net load shape, opening the door for storage to supply capacity value



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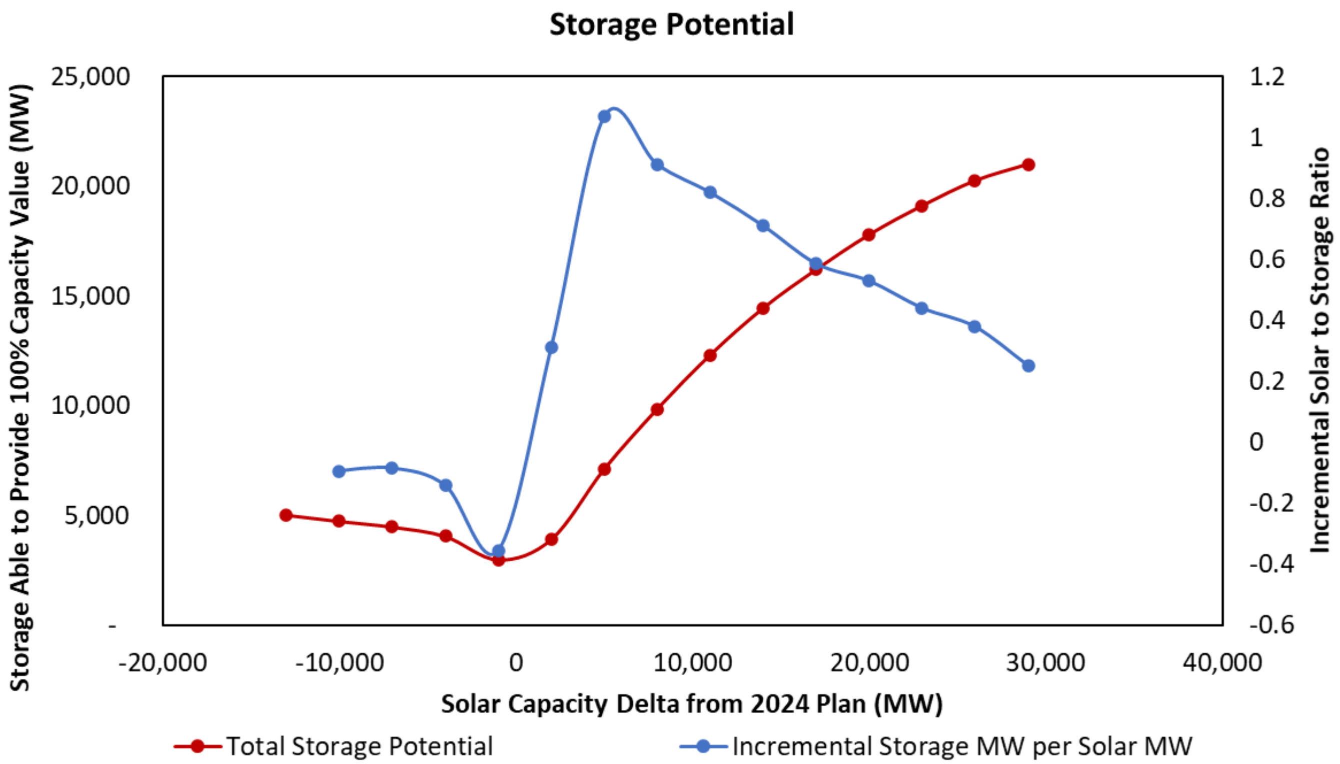
Storage Scenario

- **With 2024 Fleet, <3,000 MW of 4-hour storage can supply full capacity value**
  - Storage EORM/MERM curve will be simulated with the high renewable scenario which has the potential for 15+GW of storage to supply capacity value.



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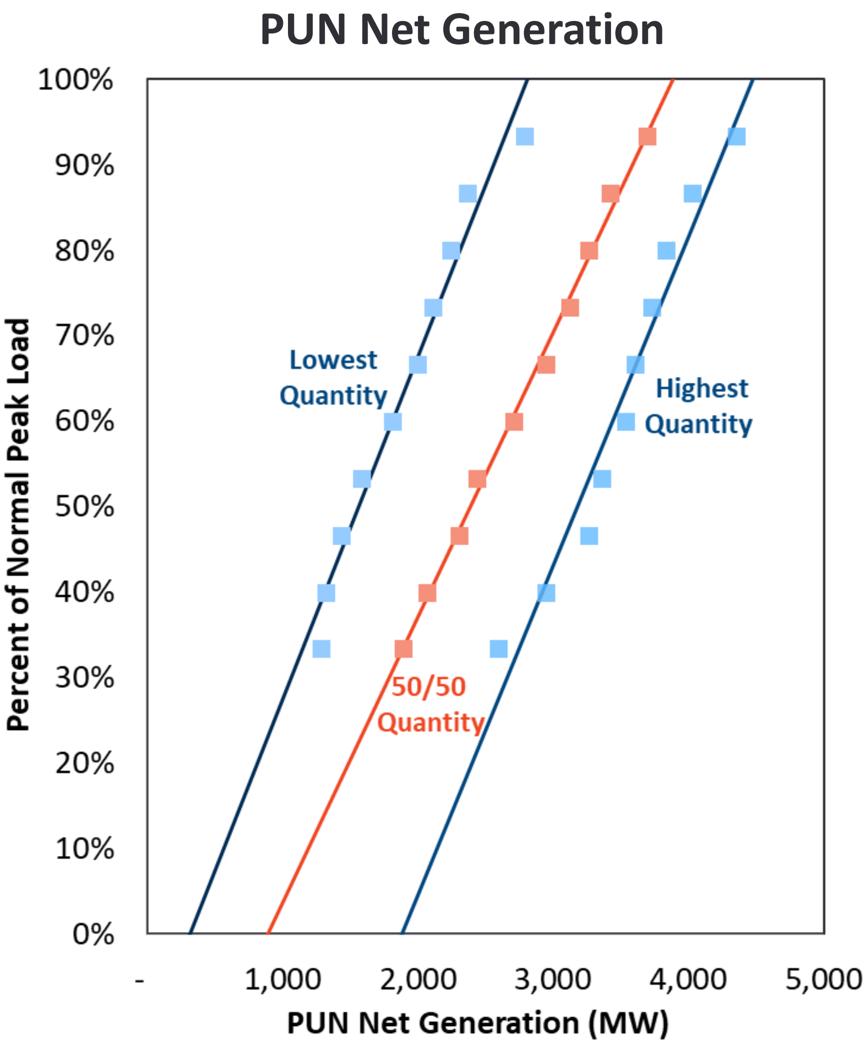
Backup Slides

Generation Resources
Private Use Networks

Net Gen Supply Curve

- Modeled as probabilistic quantity of net output, with 10 different possible quantities at any given load level
- Expected quantity increases with load level, based on realized net generation levels at normalized load levels in 2012-2019



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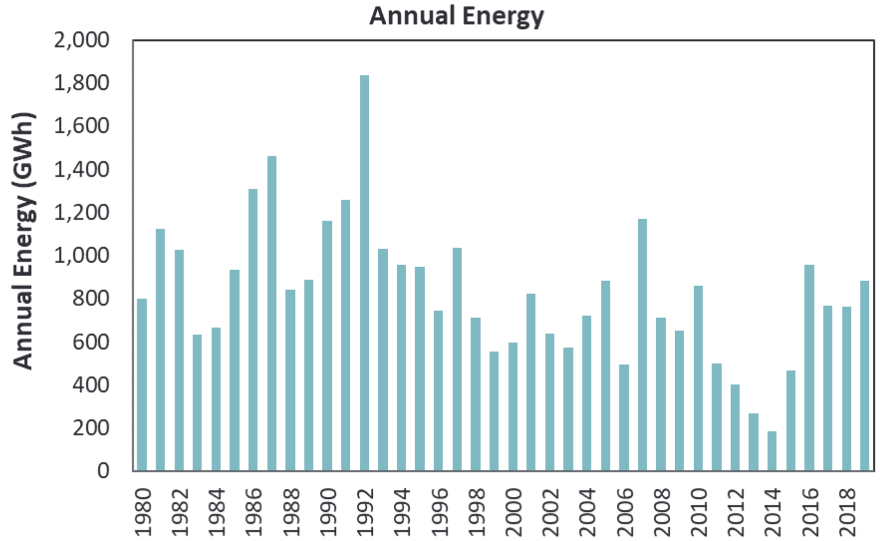
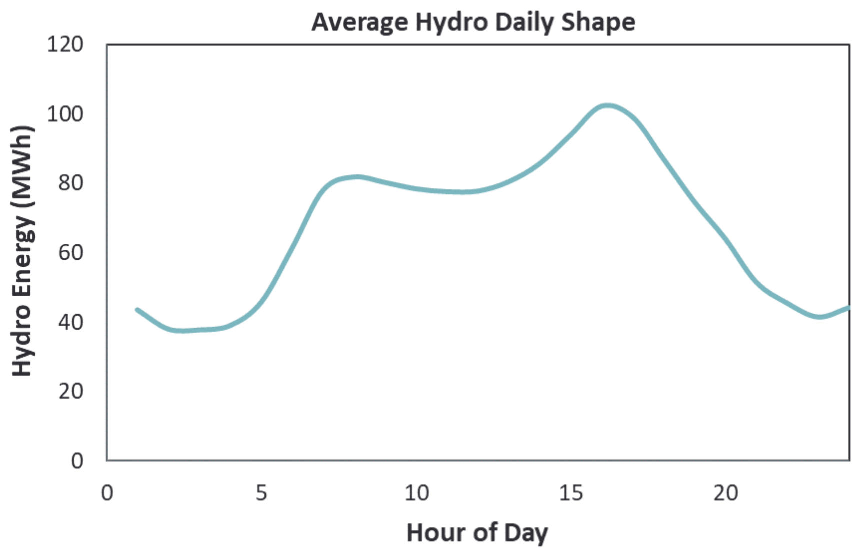
Generation Resources Hydroelectric

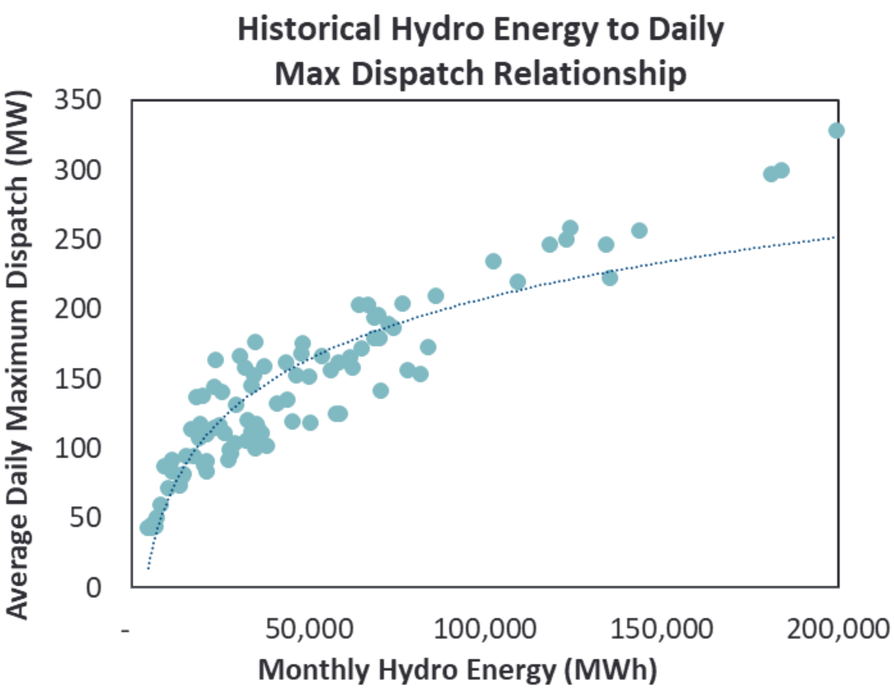
- 558.1 MW nameplate
- Characterized resources based on:
  - 8 years of hourly data from ERCOT
  - 40 years of monthly data from EIA 923
- Hydro resources modeled with different parameters each month:
  - Monthly total energy output
  - Daily maximum output
  - Daily minimum output
  - Monthly maximum output
- Energy is primarily scheduled to shave peak loads consistent with historical operations
- Unscheduled hydro capacity (monthly capacity minus output) counts toward RRS and ORDC x-axis

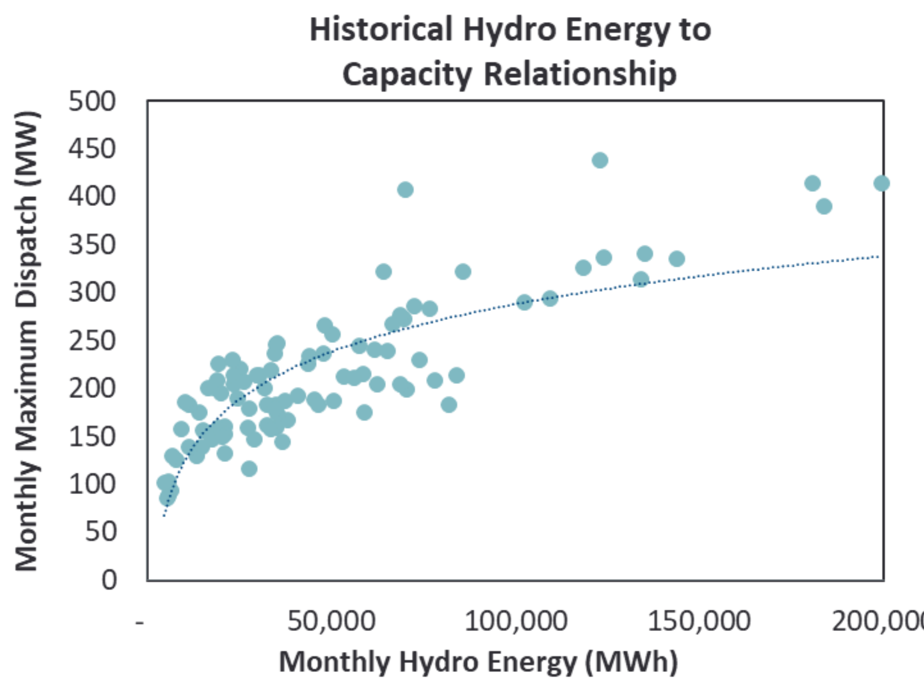




Generation Resources Hydroelectric, continued

- Historical Hydro Energy to Daily Max Dispatch Relationship
  - Curve fit equation used to determine input for each month into SERVM for daily maximum output
  - Similar curve developed for daily minimum dispatch
- Historical Hydro Energy to Capacity Relationship
  - Curve fit equation used to determine maximum capacity for each month
  - Emergency capacity of 49.25 MW modeled for drought conditions and 116.15 MW modeled for all other months





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Generation Resources
Storage

The following assumptions were made for the storage resources:

- **Economic Commitment and Dispatch**
- **Charges from the Grid**
- **Any Unit Without Provided Charging Capability was Assumed to Have a 4 Hour Storage Capability**
- **85% Round Trip Efficiency**

Generation Resources
Inclusion and Exclusion of Resources

In general, we use the 2020 LTRA as the authoritative source, but use the following assumptions for including certain resource types:

- **Switchable Units**: include as internal resources, with the units that are committed off-system excluded from our model
- **New Units:** include starting in the LTRA-specified year (Note: we may exclude the some of these units with the lowest commercial probability if needed to reduce the system reserve margin to a low level)
- **Retirements:** exclude starting in the LTRA-specified year
- **Permanent Mothballs**: exclude from model

Demand-Side Resources Emergency Response Service (ERS)

Assumed ERS Quantities Available in 2024

Contract Period	Quantity			
	10-Min NWS *(MW)*	30-Min NWS *(MW)*	30-Min WS *(MW)*	Total *(MW)*
June - September				
TP1: Weekdays HE 6 AM - 8 AM	86	767		853
TP2: Weekdays HE 9 AM - 1 PM	91	820		911
TP3: Weekdays HE 2 PM - 4 PM	90	780	26	896
TP4: Weekdays HE 5 PM - 7 PM	76	666	26	767
TP5: Weekdays HE 8 PM - 10 PM	81	784		865
TP6: All Other Hours	76	710		785
October - January				
TP1: Weekdays HE 6 AM - 9 AM	95	829	5	930
TP2: Weekdays HE 10 AM - 1 PM	88	799		887
TP3: Weekdays HE 2 PM - 4 PM	88	804		892
TP4: Weekdays HE 5 PM - 7 PM	96	849	5	950
TP5: Weekdays HE 8 PM - 10 PM	93	832		925
TP6: Weekend and Holidays HE 6 AM - 9 AM	66	746	-	812
TP7: Weekend and Holidays HE 4 PM - 9 PM	66	742	-	808
TP8: All Other Hours	67	729		795
February - May				
TP1: Weekdays HE 6 AM - 9 AM	96	843	5	945
TP2: Weekdays HE 10 AM - 1 PM	89	833		922
TP3: Weekdays HE 2 PM - 4 PM	87	834		921
TP4: Weekdays HE 5 PM - 7 PM	94	877	5	976
TP5: Weekdays HE 8 PM - 10 PM	93	851		945
TP6: Weekend and Holidays HE 6 AM - 9 AM	56	740	-	795
TP7: Weekend and Holidays HE 4 PM - 9 PM	54	743	-	796
TP8: All Other Hours	65	750		816

Sources and Notes:

Total available ERS MW for 2024 June-Sept. **TP4** provided by ERCOT staff.
ERS 10-min and 30-min MW for other contract periods scaled proportionally to the 2024 LTRA summer quantity (767 MW), based on availability in 2020.
Assume an 8-hour call limit applies to both product types, resources not callable outside contracted hours.

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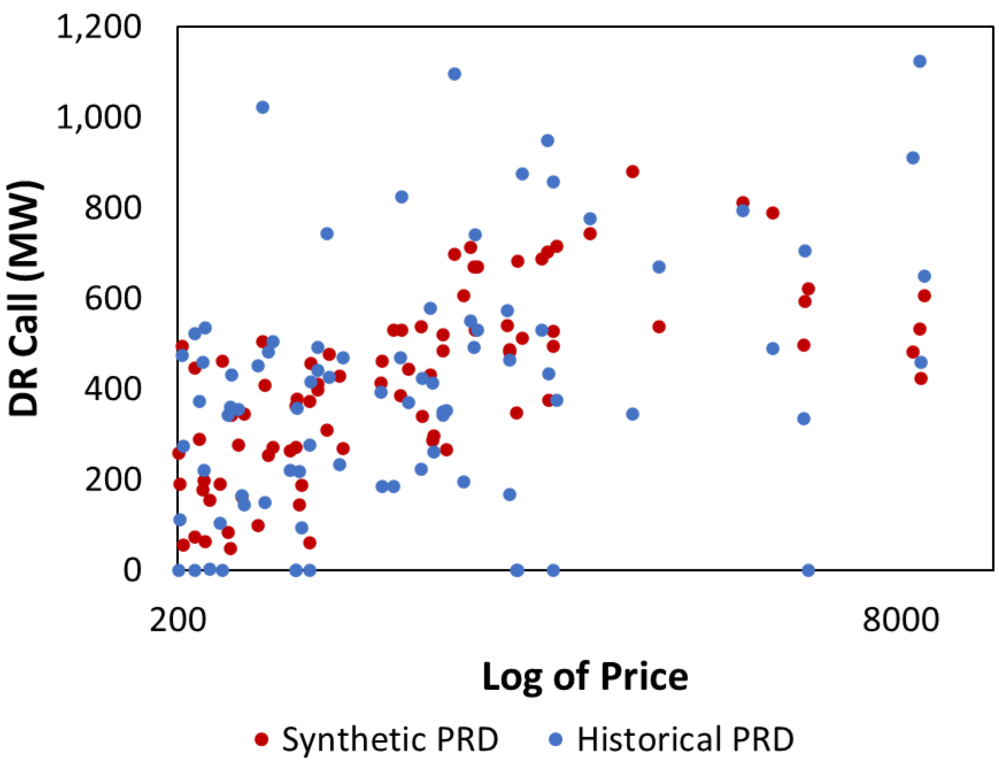
Demand-Side Resources
Non-Controllable Load Resources (LRs)

- Non-controllable LR magnitude varies by season and time of day
- Dispatched according to emergency operating procedures
  - Dispatches during EEA 2 events
  - Available reserves at 1,750 MW when dispatched
- Note: CDR quotes 1,172 MW LRS for 2024

Demand-Side Resources
Price-Responsive Demand (PRD)

PRD in Modeling

- 2019 historical PRD response used to develop modeling inputs to replicate stochastic response as a function of price



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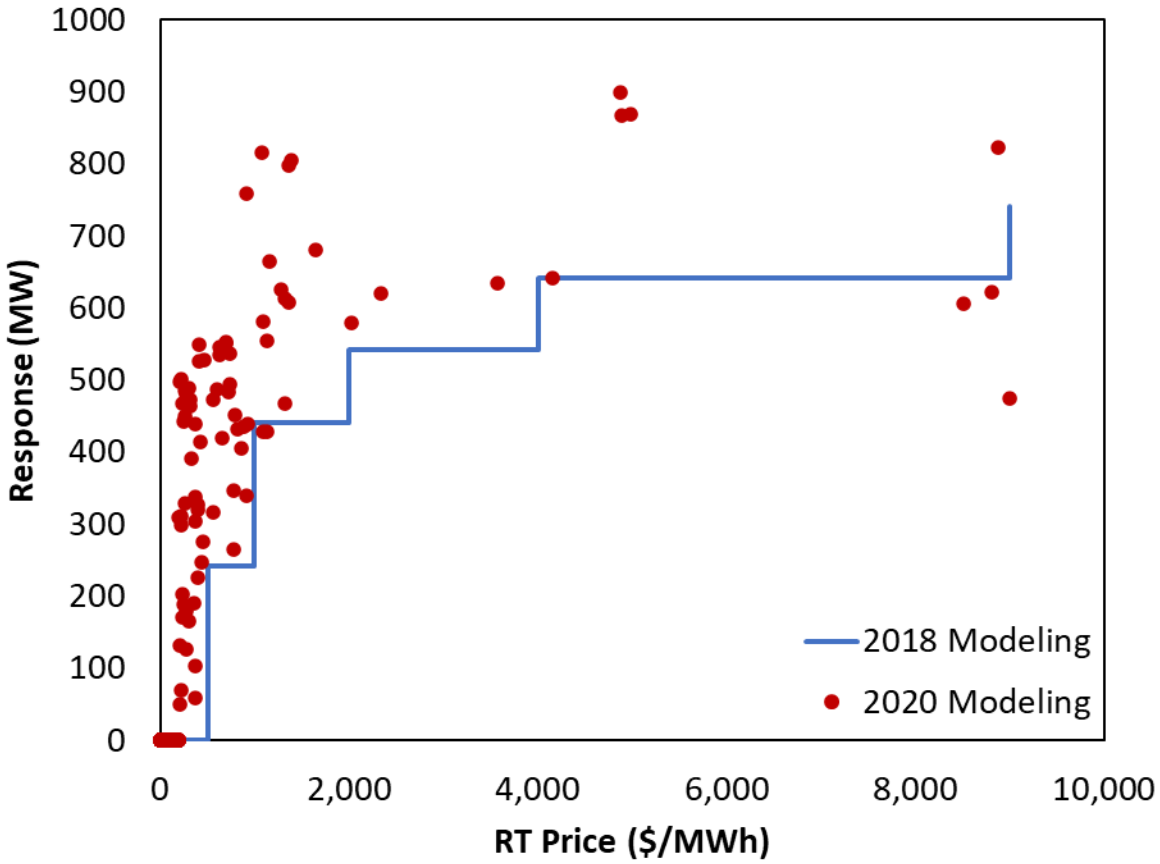
Demand-Side Resources
Price-Responsive Demand (PRD)

- Stochastic representation in 2020 modeling versus discrete representation in 2018 modeling



Fleet Summary
Operating Reserves Capability

Fleet-Wide Reserves Capability

Reserve Type	Fleet Capability *(MW)*	Notes *(MW)*
Regulation Up (Equal to Reg Down)		
Thermal Generation	6,819	Reg-capable units' 5-min ramp capability.
Batteries	1,103	Batteries can simultaneously self-schedule Reg Up + Reg Down.
Total	**7,923**	Total Reg Up + Reg Down capability is approximately double this number.
Responsive Reserve Service (RRS)		
Thermal Generation (Excluding Quickstart)	11,910	Maximum capability is lower of: (a) 10-min ramp capability, or (b) HSL - LSL.
10-Minute Quickstart	0	
Hydrosynchronous Resources	245	
Non-Controllable Load Resources	1,172	
Batteries	1,103	
Total	**14,430**	
Non-Spinning Reserve Service (NSRS)		
Thermal Generation (Excluding Quickstart)	24,283	Maximum capability is lower of: (a) 30-min ramp capability, or (b) HSL - LSL
10-Minute Quickstart	0	
30-Minute Quickstart	5,206	
Non-Controllable Load Resources	0	Allowed, but none currently provide.
Batteries	1,103	
Total	**30,592**	
Maximum Simultaneous Reserves	**52,945**	

Sources and Notes:

Calculated from ramp rates and dispatch levels provided by ERCOT

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Scarcity Conditions
Market Parameters

- **Year**: 2024
- **Offer Cap:**
  - HCAP: $9,000 (VOLL for ORDC stays at $9,000 even if PNM threshold is exceeded)
  - LCAP: $2,000 (applies only to Power Balance Penalty Curve)
- **Peaker Net Margin**:
  - Proxy Unit Strike Price: 50 x Houston Ship Channel (LCAP is never lower than this number at current HSC futures prices)
  - Threshold: 3 x CT CONE = $280,500/MW-year

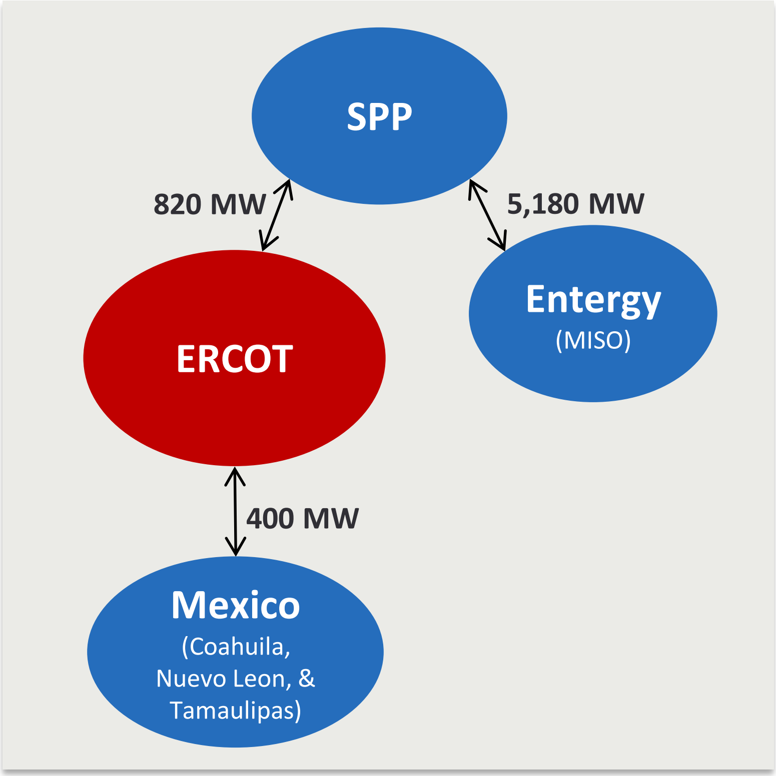
Sources and Notes:

"PUC Rulemaking to Amend PUC SUBST.R. 25.505, Relating to Resource Adequacy in the Electric Reliability Council of Texas Power Region", PUCT, Approved 10/25/2017

Threshold listed above uses the Brattle CONE estimate ($93.5/kW-yr).

System Summary
Intertie Availability

- We model total intertie capacity in line with ERCOT transmission documents
- Intertie availability at summer peak is based on historical availability consistent with the May 2020 CDR
  - The SPP-Entergy interface availability similarly modeled using a point forecast
  - Even if transmission is available, ERCOT may not be able to import in emergency if the external region is peaking at the same time



Sources:
ERCOT Ties:
http://www.ercot.com/content/wcm/key_documents_lists/90055/ERCOT_DC_Tie_Operations_Document.docx
SPP-Entergy:
www.oasis.oati.com/SWPP/SWPPdocs/Interface_Values.xls

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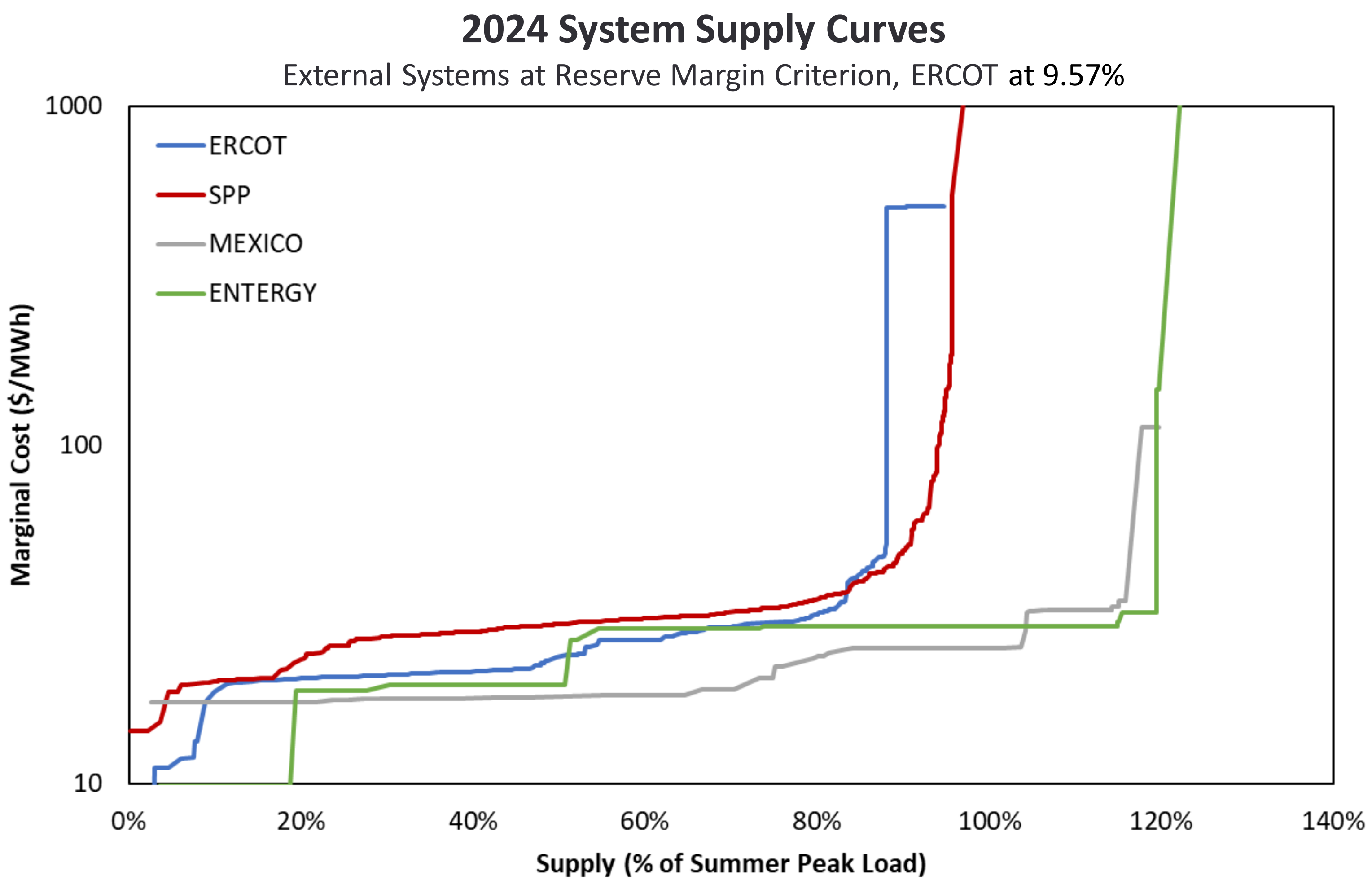
System Summary
System Supply Curves



Note: Renewable units not included, so depending on the hourly profile, the dispatch stacks could shift significantly.

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Scarcity Conditions
Emergency Procedures and Marginal Costs

Emergency Level	Marginal Resource	Amount of Resource (MW)	Trigger	Price	Marginal System Cost
n/a	Generation	Variable	Price	Approximately $20 - $250	Same
n/a	Imports	Variable	Price	Approximately $20-$250 Up to $1,000 during load shed	Same
n/a	Non-Spin Shortage	700	ORDC x-axis = 3,000 MW	$4,627 (from ORDC)*	$1,025*
n/a	Price-Responsive Demand	Variable	Price	$500 - $9,000	Same
n/a	Emergency Generation	469.8	ORDC x-axis = 2,300 MW	$5,850 (from ORDC)	$1,372
n/a	PBPC	200	Price	$1,000 - $9,000	Same
EEA 1	30-Minute ERS	691**	Spin ORDC x-axis = 2,300 MW	$5,850 (from ORDC)	$1,372
EEA1	Spin Shortage A	550	Spin ORDC x-axis = 2,300 MW	$7,492 (from ORDC)*	$1,856*
EEA 2	TDSP Load Curtailments	262	Spin ORDC x-axis = 1,750 MW	$9,000 (from ORDC)	$2,469
EEA 2	Load Resources in RRS	1,172***	Spin ORDC x-axis = 1,750 MW	$9,000 (from ORDC)	$2,469
EEA 2	10-Minute ERS	76**	Spin ORDC x-axis = 1,750 MW	$9,000 (from ORDC)	$2,469
EEA3	Spin Shortage B	750	Spin ORDC x-axis =1,750 MW	$9,000 (from ORDC)	$3,562*
EEA 3	Load Shed	Variable	Spin ORDC x-axis = 1,000 MW	VOLL = $9,000	Same

*: Price reflects the average price between the upper and lower level of each resource
**: 76 10NWS + 666 30NWS + 26 30WS = 767 total ERS (CDR Value). Both NWS and WS are included in the 30-Minute ERS
***: 60% of RRS

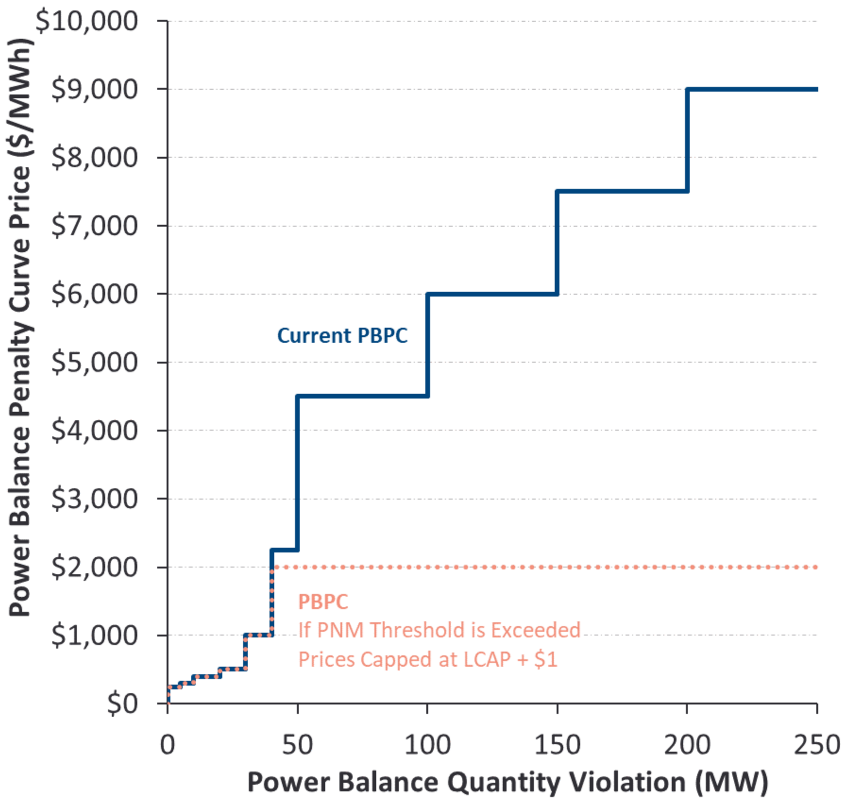
Scarcity Conditions
Power Balance Penalty Curve

Implementation

- Using PBPC curve as currently set by ERCOT; no expectation for the curve to change in upcoming years.
- Treat as a Reg Up shortage when called (can set price)
- Incur marginal system cost equal prices implied by PBPC
- Model only first 200 MW
- Highest price capped at LCAP + $1 if Peaker Net Margin (PNM) threshold is exceeded

Note: Since we model PBPC as a 200 MW resource (when none exists), we need to recognize that dispatching the PBPC depletes actual regulation reserves more than our accounting implies. So the model has to shed load at 1200 MW apparent reserves instead of 1000. And the x-axis for determining ORDC prices is given by reserves + any PBPC deployment.

Power Balance Penalty Curve



Sources and Notes:

"Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch," ERCOT 2017, p. 22.

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Scarcity Conditions
Reserve Requirements

Reserves

- Day-ahead commitments to meet ERCOT Reg Up, Reg Down, and RRS requirements (NSRS assumed non-binding)
- Shortages relative to requirement only occur when insufficient resources exist
- Modeled RRS increased to account for ERCOT Contingency Reserve Service (ECRS)

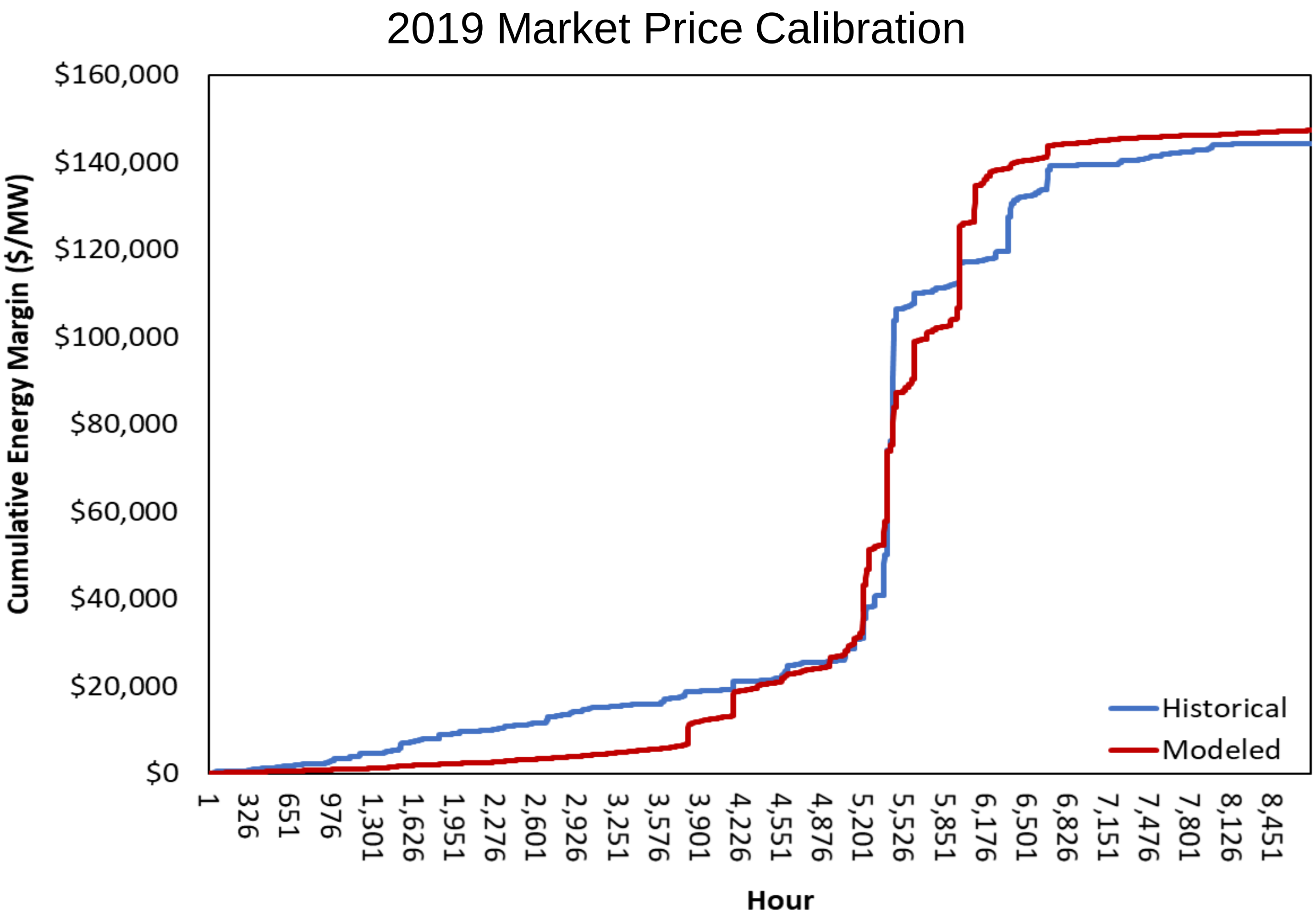
Self-Commitments

- Also model economic self-commitments if ORDC spin axis price is very high (still refining approach)
- Estimate as quantity of online capacity needed to bring total daily ORDC spin payments down to historical RRS price levels in non-peak conditions
- SERVM will commit at least this quantity unless insufficient supply exists

Reserves Requirements and ORDC Self-Commitments

Season and Hours of Day	ERCOT Day-Ahead Procurements				ORDC Spin X-Axis	
	Regulation Up (MW)	Regulation Down (MW)	RRS 10 min (MW)	NSRS 30 min (MW)	Min from RRS + Reg (MW)	Min w/ Economic Self-Commitments (MW)
Winter						
1-2 and 23-24	203	310	2998	1215	3201	4800
3-6	341	232	2972	1325	3313	4800
7-10	393	271	2844	1994	3237	4800
11-14	242	292	2844	1619	3086	4800
15-18	311	207	2844	1651	3155	4800
19-22	232	314	2868	1664	3100	4800
Spring						
1-2 and 23-24	225	400	2990	1137	3215	4800
3-6	305	238	3013	1346	3318	4800
7-10	429	259	2888	1877	3317	4800
11-14	364	237	2790	1551	3154	4800
15-18	287	243	2753	1297	3040	4800
19-22	285	400	2790	1586	3075	4800
Summer						
1-2 and 23-24	209	485	2467	1163	2676	4800
3-6	246	199	2508	1358	2754	4800
7-10	453	209	2435	1738	2888	4800
11-14	499	193	2324	1614	2823	4800
15-18	268	262	2314	1295	2582	4800
19-22	202	448	2324	1188	2526	4800
Fall						
1-2 and 23-24	199	370	2849	1186	3048	4800
3-6	280	203	2837	1451	3117	4800
7-10	411	238	2766	1747	3177	4800
11-14	374	248	2661	1642	3035	4800
15-18	301	234	2628	1332	2929	4800
19-22	217	389	2675	1260	2892	4800

SERVM Simulation Setup and Benchmarking



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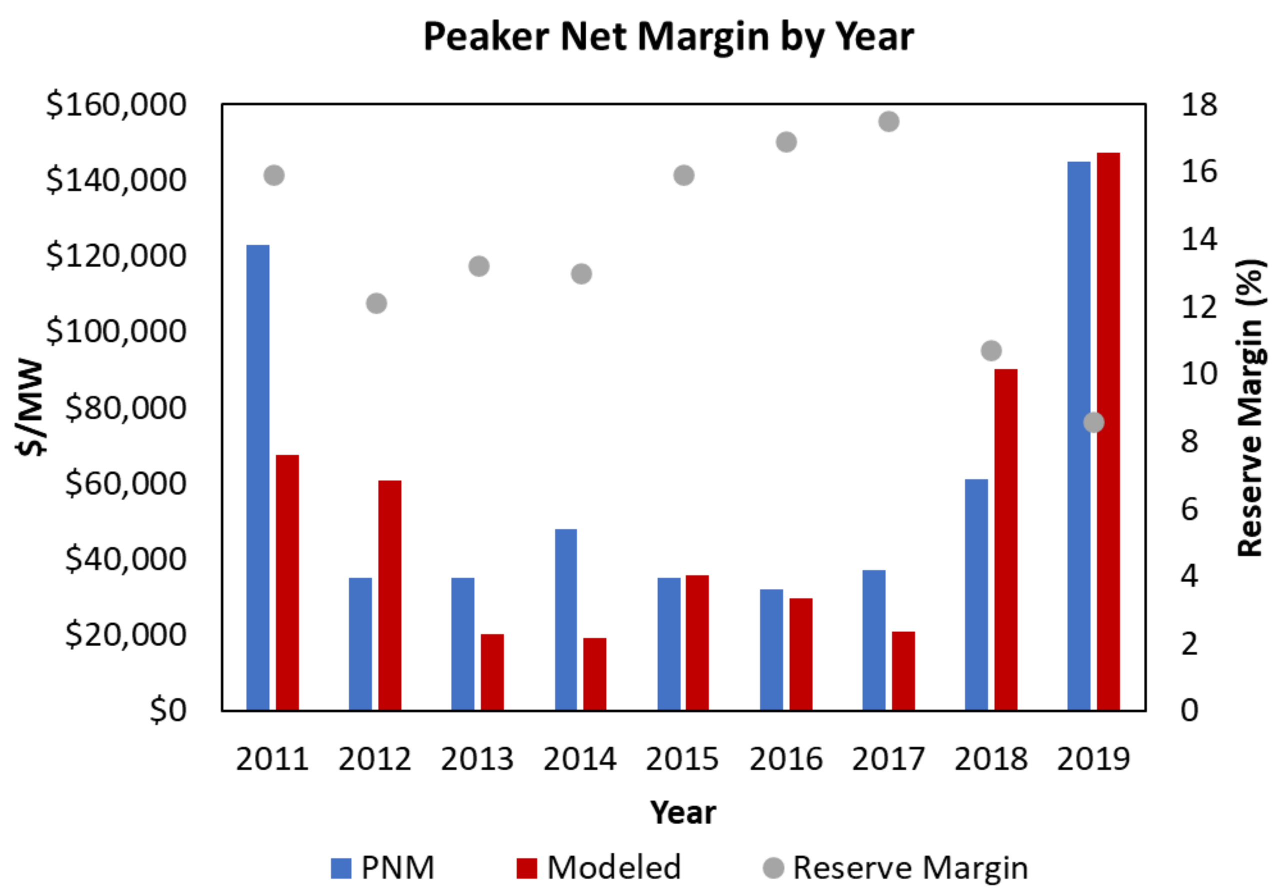
SERVM Simulation Setup and Benchmarking



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