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ANALYSIS OF RESOURCE ADEQUACY IN ERCOT—SUMMER 2019

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1. INTRODUCTION

LCG Consulting performed analysis of ERCOT for summer 2019 summer, June through September, using market simulations with LCG's UPLAN Network Power Model. Resource adequacy analysis for the region is critical during extreme summer loading conditions as the reserves have tightened because of recent retirements. The ERCOT landscape is rapidly evolving, with significant transmission changes and unprecedented growth of renewables.

For this report, LCG built scenarios examining "strained network conditions" that include high generation outages, low wind and high load forecasts. These sensitivity cases were assessed for resource adequacy to see if peak demand is served. This report further identifies strained conditions that might shift expected energy prices, Operating Reserve Demand Curve (ORDC), Peaker Net Margin (PNM), and congestion.

- Scenario 1 or Base Case: Forecasted Season Peak Load (50/50 forecast)
- Scenario 2: High Gen Outages
- Scenario 3: Low Wind
- Scenario 4: High Load

Scenario 1 assumes typical use of reserve capacity conditions while the three other scenarios represent extreme cases. For each of these scenarios, LCG used its UPLAN hourly model to simulate the summer season of 2019. With decades of benchmarking in the ERCOT system, UPLAN accurately captures the operation of the ERCOT system.

2. SCENARIO MODELING & METHODOLOGY

The nodal market simulations were performed using LCG's proprietary UPLAN Network Power Model (NPM) and PLATO-ERCOT data model at the hourly dispatch level. UPLAN authentically replicates the engineering protocols and market procedures of a system operator. Technical details on this sophisticated model are available in the Appendix of the report.

For this study, UPLAN integrates the SSWG power flow network for summer 2019 with ERCOT standard operational & planned contingencies. Transmission upgrades for summer season were added based on the Transmission Project Information Tracking (TPIT) file, published October 2018. Generation expansion and retirement assumptions rely on ERCOT publications. Monthly peak loads were modified based on the 50/50 forecast published February 2019, while the hourly load shapes use the 2018 RTP Economic Case load profiles published September 2018.Further overview on the UPLAN NPM and PLATO-ERCOT data model can be found in Appendix 1 and Appendix 2, respectively.

Table 1 – Range of Potential Risks – Summer 2019 UPLAN Scenario Assumptions

	50/50 Load Base Case	High Outages Scenario 2	Low Wind Scenario 3	High Load Scenario 4
Seasonal Load Adjustment (MW)	-	-	-	3,143
Maintenance Outages (MW)	322	322	322	322
Thermal Forced Outages (MW)	3,740	3,740	3,740	3,740
Additional Thermal Forced Outages (MW)	-	2,784	-	-
Low Wind Output Adjustment (MW)	-	-	5,756	-
Total Uses of Reserve Capacity (MW)	4,062	6,846	9,818	7,205
Capacity Available for Operating Reserves (MW)	(939)	(3,723)	(6,695)	(4,082)

3. SIMULATION RESULTS

3.1 Prices

Load zone prices are highest in the High Gen Outage scenario, where the ERCOT-wide, average, load-weighted price is $164.13, compared to $45.67 in the base case, a 259% of increase. The largest price change occurs in the North Load Zone, which sees a 295% boost. North Load Zone is the most sensitive to reserve changes in Scenario 2, as there are more generators outage in the North zone, which lead to more imports from West into North and higher congestion. In the Low Wind scenario, ERCOT-wide average load-weighted zonal prices increase 7% relative to the Base Case. Average load zone prices for all scenarios are shown below in Figure 1 and Figure 2.

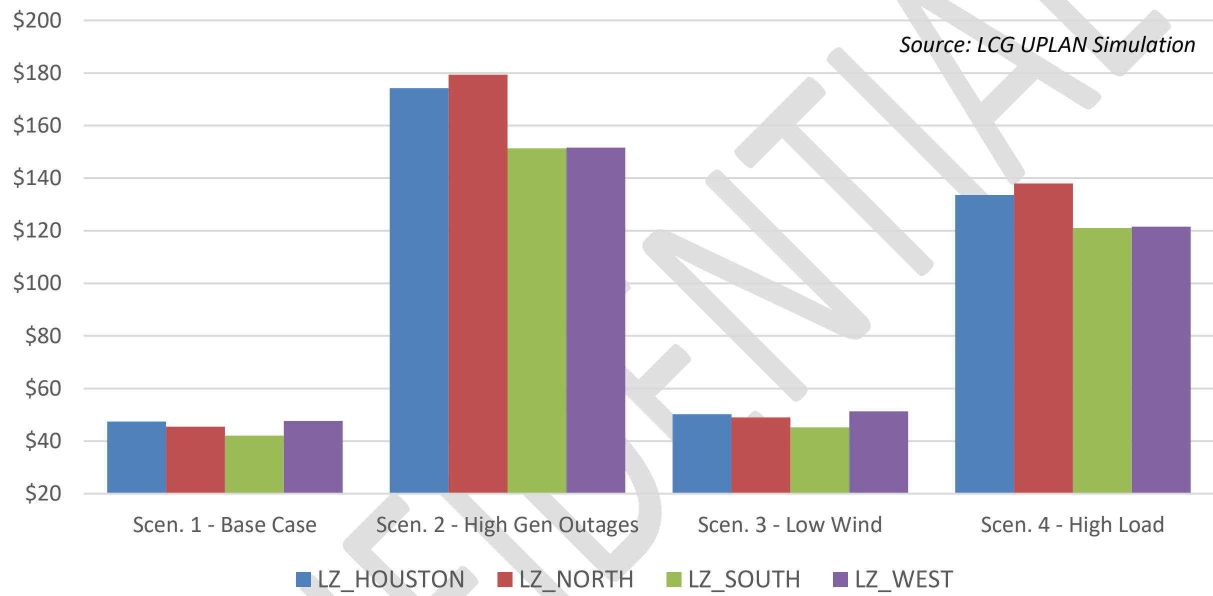

Figure 1 – Average Load-Weighted Zonal Prices by Scenario – Summer 2019 ($/MWh)

For the given sensitivity scenarios, the most sensitive Hub prices are of North and West Hub. On average, trading hub prices increase by 162.3% for High Load, by 236.2% for High Outages, and by 6.5% for Low Wind scenarios compared to the base case average price.

Trading hub price results by scenario are shown below in Figure 2.

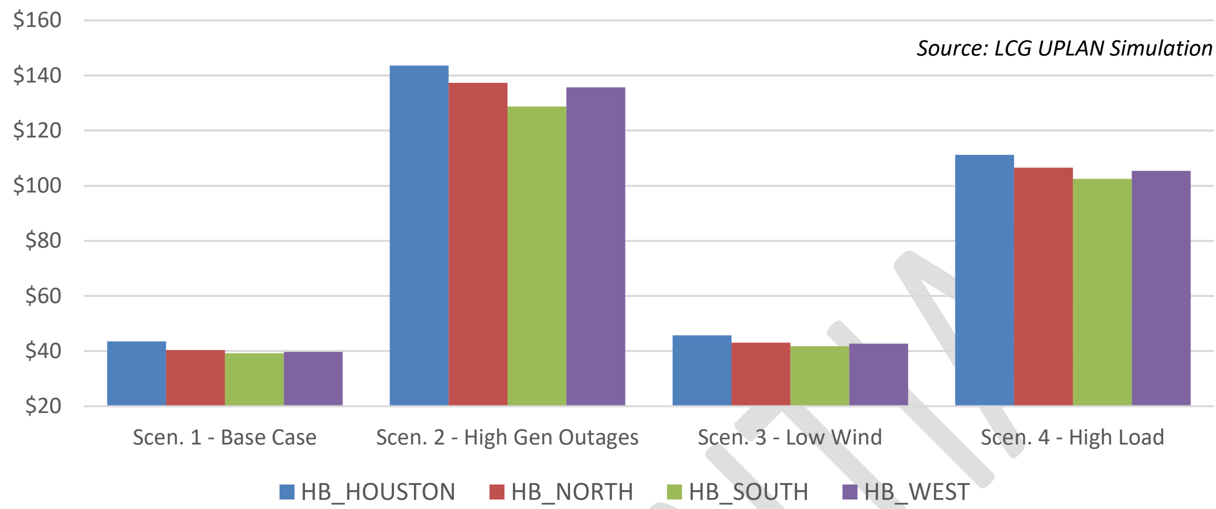

Figure 2 – Average Trading Hub Prices by Scenario – Summer 2019 ($/MWh)

Figure 3 shows the system-wide price duration curve by scenario for the top 100 hours in summer season of 2019. Here it can be seen that there are fewer occurrences of high-priced hours in the Base Case, where only 18% of all intervals have a system-wide average energy price over $50.

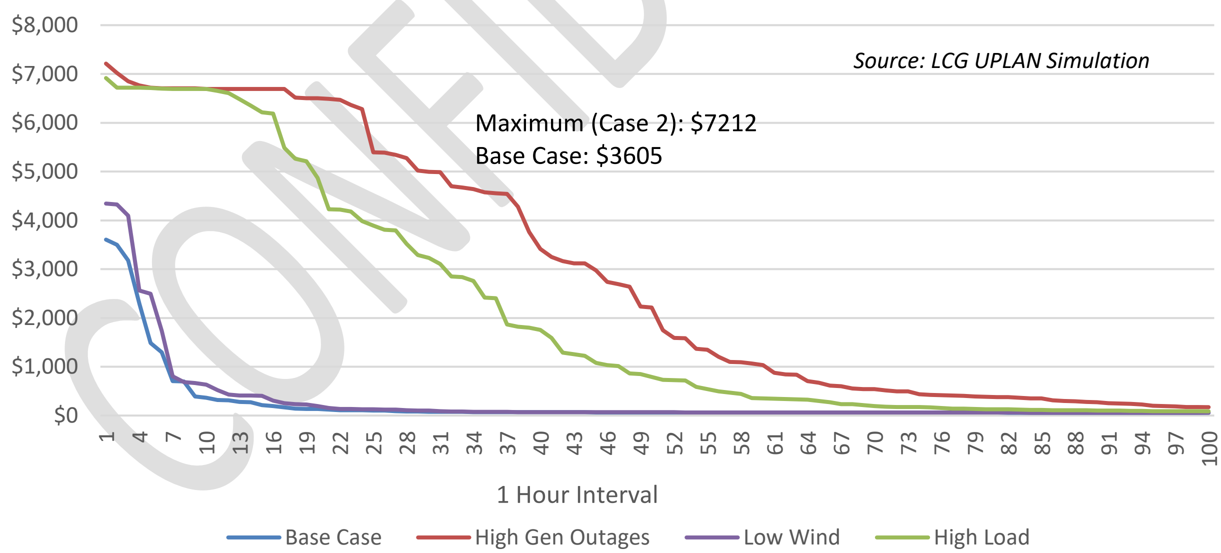

Figure 3 – System-Wide Price Duration Curve - Top 100 Hours – Summer 2019 ($/MWh) [1]

[1] Value includes ORDC price adder

As expected, the ORDC price adder increases in the extreme scenarios due to lower operating reserves. The high gen outages and high load cases result in more frequent scarcity conditions, and this is reflected in the price adder value. Hourly average Operating Reserve Price Adder is presented in Table 2 and the duration curve is shown in Figure 4 for the highest 100 hours of the summer season.

Table 2 – Average Hourly ORDC Adder ($/MWh)

Hour	Base Case	High Gen Outages	Low Wind	High Load
1	$0.00	$0.01	$0.00	$0.00
2	$0.00	$0.00	$0.00	$0.00
3	$0.00	$0.00	$0.00	$0.00
4	$0.00	$0.00	$0.00	$0.00
5	$0.00	$0.00	$0.00	$0.00
6	$0.00	$0.00	$0.00	$0.00
7	$0.00	$0.00	$0.00	$0.00
8	$0.00	$0.00	$0.00	$0.00
9	$0.00	$0.00	$0.00	$0.00
10	$0.00	$0.00	$0.00	$0.00
11	$0.00	$0.00	$0.00	$0.00
12	$0.00	$0.00	$0.00	$0.00
13	$0.01	$12.98	$0.01	$4.49
14	$3.83	$158.44	$5.24	$140.06
15	$19.06	$283.13	$27.73	$210.29
16	$62.66	$341.55	$79.67	$279.28
17	$44.42	$314.08	$65.18	$288.82
18	$19.12	$235.01	$22.90	$191.27
19	$0.83	$83.83	$1.60	$53.42
20	$0.33	$23.94	$0.49	$14.81
21	$0.00	$2.25	$0.00	$0.94
22	$0.00	$0.01	$0.00	$0.00
23	$0.00	$0.00	$0.00	$0.00
24	$0.00	$0.00	$0.00	$0.00
Average	**$6.26**	**$60.63**	**$8.45**	**$49.31**

Source: LCG UPLAN Simulation

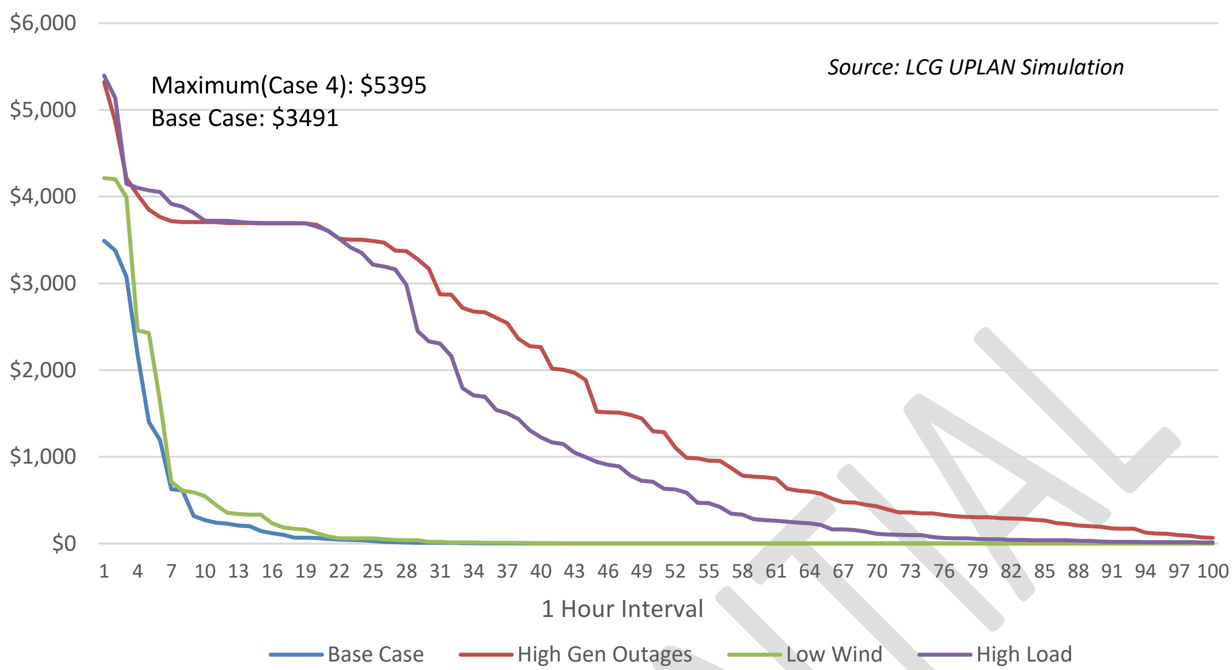

Figure 4 – Operating Reserve Price Adder Duration Curve - Top 100 hours – Summer 2019 ($/MWh)

LCG's simulation indicates that the highest value of the Peaker Net Margin (PNM), which also serves as a simplified measure of the annual net revenue of a peaking unit, corresponds to the High Gen Outage scenario. In the Base Case, the cumulative PNM value (June through September) is $47,954. During the same period, the margin is $327,787 in the High Gen Outages case, $55,396 in the Low Wind case and $240,190 in the High Load case, exceeding the 2011 levels. Simulation results show that Peaker's gain the most in August (Figure 5).

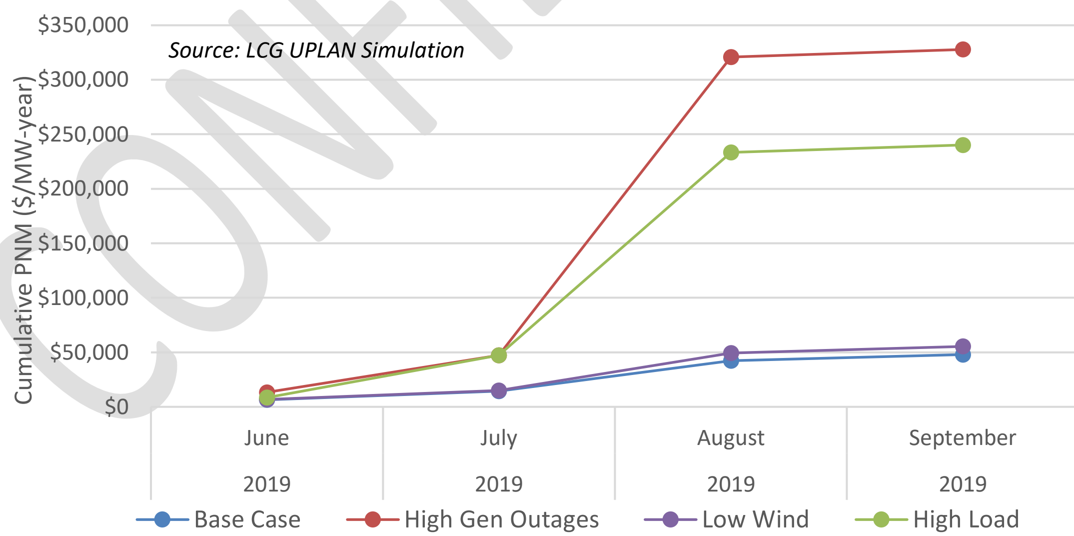

Figure 5 – ERCOT-wide Cumulative Peaker Net Margin

For additional results on generation and congestion, please contact us at julie.chien@energyonline.com to receive the full report.