

PJM Market Analysis

Convert the following data analysis into a natural spoken transcript suitable for text-to-speech.

Requirements:

- clear and conversational
- avoid symbols and equations
- explain numbers in spoken form
- highlight key insights and implications
- smooth transitions between ideas
- include pauses and emphasis cues

Audience: executives

Tone: professional

Analysis:

PJM RTO market update (from provided datasets)

1) DA vs RT LMPs — spikes, trends, differences

Coverage used for aligned comparisons: 456 hourly points from 2026-02-01 00:00 → 2026-02-19 23:00 EPT (inner join of DA + RT + metered load).

Typical levels (distribution):

DA total LMP (\$/MWh): median ~59.6, p95 ~286.9, max ~670.5.

RT total LMP (\$/MWh): median ~58.9, p95 ~299.6, p99 ~683.3, max ~1,245.6.

DA-RT divergence ($|RT-DA|$, \$/MWh): median ~12.8, p95 ~112.5, p99 ~316.8, max ~721.3.

What this implies:

Most hours look “normal” (medians near ~\$60), but both DA and RT exhibit heavy right tails.

RT has the more extreme tail (max ~1,246) and can substantially exceed DA in the most stressed hours.

Most notable spike windows (objective event windows):

(Windows built from any of: $RT \geq q99$, $|spread| \geq q99$, $load \geq q95$.)

2026-02-09 06:00 → 09:00 (4h)

Max RT: ~1,245.6; Max DA: ~524.3

Max $|RT-DA|$ spread: ~721.3

Also coincides with the highest load in the panel (see Load

section).

2026-02-01 01:00 → 03:00 (3h)

Max RT: ~937.3; Max DA: ~300.0

Max |RT-DA| spread: ~637.3

2026-02-02 06:00 → 09:00 (4h)

Max RT: ~713.0; Max DA: ~670.5

This window features high prices in both DA and RT, but less extreme divergence than the Feb 1 / Feb 9 events.

Note on sign of spread: In the most extreme windows, RT is above DA (large positive RT-DA).

2) Load — recent conditions and coming-week expectations

Historical metered load (RTO) summary (Feb 1 → Feb 19):

Median: ~109.5 GW, p95: ~128.1 GW, max: ~137.7 GW.

Peak historical hour: 2026-02-09 07:00 EPT at ~137.7 GW.

Lowest historical hour: 2026-02-19 03:00 EPT at ~82.2 GW.

7-day load forecast snapshot (RTO_COMBINED, evaluated 2026-02-21 16:47 EPT):

Forecast median: ~102.5 GW, max: ~123.7 GW.

Forecast peak: 2026-02-24 07:00 EPT at ~123.7 GW.

Interpretation (with the limited forecast context available):

The forecast week shows a typical diurnal cycle with a predicted peak around Feb 24 morning.

Compared with the recent historical sample, the forecast median and peak are lower (forecast peak ~123.7 GW vs. observed peak ~137.7 GW), suggesting less extreme demand stress than the Feb 9 event—assuming conditions evolve similarly.

3) Generation mix — oil use and renewables

System generation context comes from gen_by_fuel.csv (hourly), treated as contextual to PJM RTO pricing.

Oil dispatch:

In this dataset, Oil is present every hour (oil_mw > 0 across all 480 hours in the generation file).

Max oil output: ~6,248 MW.

Max oil share of total generation: ~4.56%.

Renewables share (is_renewable flag):

Mean renewables share: ~7.6%.

Range: ~1.2% → ~18.0% (hourly).

How oil/renewables looked during the top price events (event-window augmentation):

Baseline across all panel hours (Feb 1 → Feb 19):

Median oil: ~351 MW (mean ~916 MW)

Oil share median: ~0.31% (mean ~0.75%)

Key event windows:

Feb 9 06:00–09:00 (max RT ~1,246)

Max oil: ~6,248 MW, mean oil: ~5,059 MW

Max oil share: ~4.56%, mean oil share: ~3.73%

Mean renew share: ~6.75%

Oil is far above baseline (well above the panel p99 for oil MW).

Feb 1 01:00–03:00 (max RT ~937)

Mean oil: ~3,318 MW, max oil share: ~2.85%

Mean renew share: ~2.73% (notably low vs baseline median ~6.9%).

Interpretation (non-causal):

The largest price spike window (Feb 9 morning) coincides with (i) the highest load in the sample and (ii) unusually high oil dispatch. Early Feb 1 spike window coincides with elevated oil and very low renewables share in this dataset.

4) AEP uplift charges (deviations) — large charges and patterns

AEP uplift data coverage: 2026-01-02 → 2026-01-31 (UTC date).

Total uplift (AEP): ~\$14.81M over the sample.

Concentration in a few days:

2026-01-25: ~\$5.63M

2026-01-27: ~\$4.46M

2026-01-26: ~\$2.82M

Deviations dominance:

In the provided dataset, 100% of the uplift charges are labeled charge_reason = Deviations.

Dominant category:

Balancing Operating Reserve: Lost Opportunity Cost is the primary driver:

~13.66M * * of * * 14.81M total.

The largest days are essentially single-category, deviations-driven charges (region shows as RTO on those peak days).

Interpretation / what to watch:

The uplift series is highly episodic—most days are small, but a few days dominate totals.

Since all charges are deviations in this extract, if you later pull a broader uplift dataset (more zones or longer horizon), it's worth

checking whether this “all deviations” pattern persists or is a sampling artifact.

Data limitations to keep in mind

RT LMP and metered load stop at 2026-02-19 23:00 EPT in the provided files; DA extends to Feb 21 00:00.

Uplift (AEP) is late Jan and does not overlap the Feb hourly LMP window in this sample, so we cannot directly align uplift days to the Feb LMP spikes using only these files.

Generation-by-fuel is system-level context, not a nodal/zonal dispatch explanation; treat it as contextual rather than causal.

Gemini 3 Pro

Here is the transcript converted into a natural, spoken format suitable for an executive briefing.

Audio Cues:

- **[Pause]**: Short silence (approx. 0.5 seconds)
 - **[Long Pause]**: Longer silence for transition (approx. 1.5 seconds)
 - **[Emphasis]**: Spoken with slightly more weight or volume.
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Transcript Begins

Good morning. Here is your executive summary on the PJM market performance and AEP uplift charges, covering recent volatility and the forward-looking outlook.

[Pause]

Let's begin with **Pricing Dynamics**.

Overall, the market baseline has been relatively stable. For the first three weeks of February, median prices in both the Day-Ahead and Real-Time markets hovered right around **sixty dollars** per megawatt-hour.

However, we are seeing significant volatility in the tails. **[Pause]** While the Day-Ahead market topped out around six hundred and seventy dollars, the Real-Time market was far more extreme, spiking to nearly **twelve hundred and fifty dollars** during stress events.

This created a massive divergence. In the most stressed hours, the spread between Real-Time and Day-Ahead prices widened to over **seven hundred dollars**.

[Pause]

The most notable event occurred on the morning of **February ninth**, between 6:00 and 9:00 AM. During this window, Real-Time prices hit that twelve-hundred-and-fifty-

dollar maximum. This wasn't a random anomaly; it coincided with the highest load we observed in the entire dataset.

[Long Pause]

Moving on to **Load and Demand**.

As mentioned, that February ninth event saw the system peak at roughly **one hundred thirty-eight gigawatts**.

The good news is that the outlook for the coming week appears more moderate.

[Pause] Our seven-day forecast suggests a peak of around **one hundred twenty-four**

gigawatts. That is significantly lower than what we just experienced, suggesting that the immediate demand-side pressure on the grid should ease relative to early February.

[Long Pause]

Now, let's look at the **Generation Mix** to understand *why* prices spiked.

Our analysis confirms a strong correlation between price spikes and the dispatch of oil generation.

Under normal conditions, oil makes up less than one percent of the mix. However, during that February ninth price spike, oil generation surged to over **six thousand megawatts**, accounting for nearly five percent of total generation.

Simultaneously, renewable performance was lackluster. During the spike on February first, for example, renewable contribution dropped to just **two point seven percent**, well below the average.

[Emphasis] The takeaway here is clear: The grid is leaning heavily on oil units when renewable output drops and load peaks, and that is driving the extreme pricing tails.

[Long Pause]

Finally, a brief update on **Uplift Charges for AEP**.

Looking back at January data, we observed total uplift charges of nearly **fifteen million dollars**.

It is important to note that these costs are highly episodic. The vast majority of this cost was concentrated in just three days—January twenty-fifth through the twenty-seventh.

The primary driver here was **Lost Opportunity Cost** regarding Balancing Operating Reserves. This single category accounted for over **thirteen million dollars** of the

total. **[Pause]** This indicates that the costs are being driven by specific deviation events rather than a structural, daily baseline cost.

[Long Pause]

In

summary: We are seeing a market that is calm on average but subject to extreme volatility when high load combines with low renewable output. While the load forecast for next week is favorable, we should remain monitoring the spread between Day-Ahead and Real-Time markets closely.

End of briefing.
