CEG gideon lens

Constellation Energy Corporation (NASDAQ: CEG) — Gideon Lens Production ER2

Report ID: CEG-ER2-20260806-pulse-cio-20260806T090230+0800 **Report date:** 2026-08-06 **Information cutoff:** 2026-08-06 09:02:30 SGT **Price anchor:** USD 265.12, XNAS completed close on 2026-08-05 **Production run:** pulse-cio-20260806T090230+0800 **Research authority:** underwriting only; no ranking, sizing, portfolio mutation, message, order, or execution authority

Verdict: PASS

Scorecard:

Gate	Result	Notes
Management	YELLOW	Strong operator; Calpine integration, leverage, and returns remain unproved
Moat	YELLOW	Scarce nuclear assets, but fleet-wide high returns through 2046 unproved
P/E <= 15 on confident EPS at TTM + 5 calendar years	FAIL	Base value USD 183.60; cushion negative 30.75%
Compounder Score	Audited 39/100	Reject; scarce assets do not offset missing ROIIC proof and failed returns
Business Quality Score	Audited 38/80	Strong nuclear core, but combined-company economics remain unproved
20% Return UW Score	Audited 1/20	Today's price does not support the 20% stretch hurdle

One-line thesis (or reason to pass): CEG owns exceptional nuclear and power-market assets, but Calpine integration and durable combined-company returns remain unproved, while USD 265.12 prices in earnings and shareholder returns that the confident base case cannot support.

Security return underwriting (mandatory even when the verdict is PASS):

Measure	Result	Notes
Primary valuation method	P/E	One audited method used for every scenario, probability weighting, reverse-return diagnostic, and net-SGD overlay
Gross local-currency bear / base / bull IRR	-100.00% / -2.74% / 14.66%	Five-year annualized shareholder return in USD
Probability-weighted gross local-currency IRR	-4.95%	CAGR of probability-weighted terminal wealth; 30% bear / 55% base / 15% bull
Return bridge	USD 265.12 to USD 0.00 / 230.73 / 525.35	TTM operating anchor 2026-03-31, horizon 2031-03-31; terminal EPS × exit P/E plus distributions, with no post-P/E debt adjustment

Gross underwriting is in USD; net-SGD appears separately. The governed operating and compounding horizon is 2026-03-31 to 2031-03-31. The sealed USD 265.12 close observed on 2026-08-05 is applied to that five-year TTM horizon. Current diluted EPS is USD 11.723815 and P/E is 22.613799x. Terminal value is EPS × scenario P/E plus dividends once; cash/debt affect EPS but are not adjusted again. Current cash/gross debt are USD 0.800B/USD 22.466B; bear, base, and bull terminal contexts are USD 0.800B/22.466B, USD 1.200B/19.066B, and USD 2.000B/17.466B. Terminal diluted shares are 354.133M/347.016M/343.458M. The double-count check passes.

Bear-case operating and return bridge

Bear case	Start (2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	USD 29.867B	USD 33.342B	2.23%	Restrained regional growth is offset by spread compression, support roll-off, and weak Calpine conversion
Operating margin	16.63%	(4.47%)	(21.10) pp	RNF deterioration and consolidated cost pressure produce a statutory operating loss
Operating earnings	USD 4.967B	USD (1.489)B	N/M	Statutory operating income equals revenue multiplied by modeled consolidated operating margin
Diluted share count	354.000M	354.133M	0.01%	Deleveraging and weak cash conversion prevent net share retirement
EPS	USD 11.723815	USD (4.7972)	N/M	Statutory diluted EPS used in the shareholder bridge
Valuation	22.61x P/E	0.00x P/E	(22.61)x	Negative EPS makes a positive P/E non-meaningful; limited-liability floor applied
Share value	USD 265.12	USD 0.00	N/M	USD (4.7972) EPS × 0.00x; no net-debt adjustment after P/E
Annual dividend	USD 1.706	USD 0.00	Suspended	Explicit zero-distribution diagnostic under sustained statutory loss
Dividend yield	0.64%	N/M	N/M	Terminal share value and annual dividend are both zero
Five-year dividends	-	USD 0.00	cumulative	Distributions are explicitly zero in the bear diagnostic
Total ending value	USD 265.12	USD 0.00	-100.00% gross local IRR	Terminal share value plus cumulative distributions

Base-case operating and return bridge

Base case	Start (2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	USD 29.867B	USD 43.418B	7.77%	Regional load, contract coverage, and normalized Calpine ownership support growth without bull assumptions
Operating margin	16.63%	13.73%	(2.90) pp	Higher revenue is diluted by Calpine mix, operating costs, and conservative RNF conversion
Operating earnings	USD 4.967B	USD 5.962B	3.72%	Statutory operating income equals revenue multiplied by modeled consolidated operating margin
Diluted share count	354.000M	347.016M	(0.40%)	USD 4.0B of buybacks partly offset by 7.250M of SBC issuance
EPS	USD 11.723815	USD 12.2399	0.87%	Statutory diluted EPS used in the shareholder bridge
Valuation	22.61x P/E	18.00x P/E	(4.61)x	Exit is below current P/E and near the profitable FY2024 historical anchor
Share value	USD 265.12	USD 220.3182	(3.63%)	USD 12.2399 EPS × 18.00x; no net-debt adjustment after P/E

Base case	Start (2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Annual dividend	USD 1.706	USD 2.4977546	7.92%	Five annual payments begin at the source-bound current rate and grow 10%
Dividend yield	0.64%	1.13%	+0.49 pp	Annual dividend divided by endpoint share value
Five-year dividends	-	USD 10.4153006	cumulative	Five annual payments grown at 10%
Total ending value	USD 265.12	USD 230.7335006	-2.74% gross local IRR	USD 220.3182 share value plus USD 10.4153006 distributions

Bull-case operating and return bridge

Bull case	Start (2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	USD 29.867B	USD 51.174B	11.37%	Strong load conversion, contracts, uprates, fleet availability, and Calpine integration cooperate
Operating margin	16.63%	23.09%	+6.46 pp	High RNF conversion and controlled costs lift statutory margin above the TTM anchor
Operating earnings	USD 4.967B	USD 11.817B	18.93%	Statutory operating income equals revenue multiplied by modeled consolidated operating margin
Diluted share count	354.000M	343.458M	(0.60%)	Full USD 5.0B authorization is used while SBC remains modeled
EPS	USD 11.723815	USD 25.7256	17.02%	Statutory diluted EPS used in the shareholder bridge
Valuation	22.61x P/E	20.00x P/E	(2.61)x	Exit is below current P/E and within profitable historical/forward evidence
Share value	USD 265.12	USD 514.5120	14.18%	USD 25.7256 EPS × 20.00x; no net-debt adjustment after P/E
Annual dividend	USD 1.706	USD 2.6844240	9.49%	Conditional bull cash path grows the dividend 12% annually
Dividend yield	0.64%	0.52%	(0.12) pp	Annual dividend divided by endpoint share value
Five-year dividends	-	USD 10.8379576	cumulative	Five annual payments grown at 12%
Total ending value	USD 265.12	USD 525.3499576	14.66% gross local IRR	USD 514.5120 share value plus USD 10.8379576 distributions

Probability-weighted terminal wealth is USD 205.705918969424 per share: 30% × USD 0.00 + 55% × USD 230.7335006 + 15% × USD 525.34995759616. Annualizing against USD 265.12 produces negative 4.9480875253%, not an average of scenario IRRs.

CIO actionability (separate from ER2 underwriting):

Measure	Result	Notes
Status	PASS	This is separate from the ER2 verdict; current returns and downside do not support capital action
Bear / Base / Bull net SGD IRR	-100.00% / -3.76% / 15.40%	Five-year annualized after 35bp entry/exit costs, 30% dividend withholding, and scenario FX
Probability-weighted net SGD IRR	-5.32%	30% bear / 55% base / 15% bull; CAGR of weighted terminal net-SGD wealth

Measure	Result	Notes
10% mandate hurdle	FAIL	Base and probability-weighted cases are both below 10%
15% stretch hurdle	FAIL	Bull alone clears 15%; base and weighted cases do not
Downside and portfolio fit	FAIL	Bear downside is unacceptable; actual portfolio fit is UNAVAILABLE due to missing portfolio context
Proposed sizing ceiling	none	No sizing proposal; any future action requires owner approval

The diagnostic uses USD/SGD 1.28068, 35bp entry/exit costs, 30% dividend withholding, and exit FX of 1.15/1.24/1.34. It uses the same P/E values as the gross model. Missing portfolio context constrains only fit and sizing.

Trade execution authorized: NO

Kill / trigger criteria:

- BUY trigger: price at or below USD 183.60, the confident base EPS of USD 12.2399 at 15x, while Management and Moat also upgrade to PASS; at USD 265.12 the cushion is negative 30.75%.
- PASS trigger: rolling-four-quarter Calpine RNF below USD 3.5B at the first full-year ownership window, confirmed at the next update or obscured by unreconciled reclassification.
- PASS trigger: rolling nuclear capacity factor below 92% with rising non-refueling outage days, or slippage in material license/restart milestones.
- PASS trigger: end-2027 deleveraging below the stated USD 3.4B while buybacks continue or recurring integration adjustments obscure cash conversion.
- Upgrade to BUY only if full-year Calpine cash conversion and acquisition-inclusive ROIIC are demonstrated, debt falls as promised without reliability loss, Management and Moat clear, and the current price is below the P/E-15 value with positive cushion.

Research sizing if actionable: none. This conclusion proposes no allocation and cannot authorize a trade.

Stage 0 — Time anchor

- **Today:** 2026-08-06.
- **Fiscal convention:** fiscal year ends December 31.
- **Most recently reported quarter:** Q1 FY2026 ended 2026-03-31; the scheduled Q2 release falls after the 09:02:30 SGT information cutoff and is a later refresh trigger only.
- **TTM anchor:** Q2 FY2025 + Q3 FY2025 + Q4 FY2025 + Q1 FY2026, ending 2026-03-31.
- **Forward horizon:** TTM + 5 calendar years = 2031-03-31, exactly five years.

Stage 1 — Disqualifier sweep

Check	Tag	Evidence
ROIC persistently at least 15%	YELLOW	Nuclear operations are strong, but acquisition-inclusive ROIIC and combined-company ROIC are not yet proved
FCF conversion healthy	YELLOW	Collateral and working-capital volatility depress reported conversion; audited TTM conversion is only 30.73%
Net debt / EBITDA below 3x or justified	YELLOW	USD 21.666B cash-only net debt makes Calpine cash delivery and deleveraging material
End markets stable or growing	GREEN	Grid reliability, electrification, and data-center demand support load, though monetization is not automatic
Governance clean	GREEN	No controlling holder, related-party, or chronic dilution concern emerged

Check	Tag	Evidence
AI disruption manageable	GREEN	AI raises power demand; customer workflow automation is a secondary retail-margin risk
Pricing power exists	YELLOW	Long-tenor nuclear/site contracts show scarcity, but blended fleet and retail pricing power is unverified

Management

Management is **YELLOW**. Joe Dominguez and the separation-era team have earned credibility through exceptional nuclear availability, repeated guidance delivery, coherent long-term contracting, price-aware repurchases, and minority-shareholder governance. The unresolved issue is stewardship of the enlarged enterprise. Calpine consideration rose materially by closing, gross debt reached USD 22.466B, the combination has only one reported quarter, and compensation relies on adjusted FCF and TSR without explicit ROIC. A PASS requires the promised USD 3.4B deleveraging by end-2027, approximately USD 2 of durable EPS accretion and more than USD 2B of annual FCF without recurring integration exclusions, and source-bound project returns that do not compromise fleet reliability.

Moat

Moat and the **2046 test are YELLOW**. Scarce licensed nuclear sites, fleet-level operating skill, interconnections, the Geysers, investment-grade contracting capacity, and 20-year hyperscaler agreements form a real physical moat. Yet a large part of the post-Calpine business remains exposed to commodity spreads, retail competition, regulation, collateral, and gas-fleet transition. A specific 2046 business is plausible, and several licenses and contracts reach the test year, but durable high returns still require successful relicensing, recontracting beyond the first hyperscaler cohort, post-PTC economics, and proof that Calpine earns more than cycle-average commodity returns.

Stage 5 synthesis

All 11 tie-outs passed. The TTM base is USD 29.867B revenue, USD 4.967B operating income, and USD 11.723815 EPS. At 2031-03-31, base reaches USD 43.418B revenue, USD 5.962B operating income, USD 4.247B net income, 347.016M shares, and USD 12.2399 EPS. At 15x, that is USD 183.60 against USD 265.12, a negative 30.75% cushion; required EPS is USD 17.6747. Bear/base/bull EPS are negative USD 4.7972 / USD 12.2399 / USD 25.7256 at 30%/55%/15%; only bull clears P/E 15. Probability-weighted EPS is USD 9.152. Statutory and segment bridges reconcile, the four quarters do not overlap, and the tested sensitivities do not rescue base valuation.

Case	Revenue USD B	Operating income USD B	Net income USD B	EPS USD	EPS × 15	P/E-15 result
Bear	33.342	(1.489)	(1.699)	(4.7972)	(71.96)	FAIL
Base	43.418	5.962	4.247	12.2399	183.60	FAIL
Bull	51.174	11.817	8.836	25.7256	385.88	PASS

Red team

The red team says the thesis does **not** survive at USD 265.12. Its strongest argument is that Calpine's unseasoned earnings, opaque unallocated profit, poor demonstrated cash conversion, and acquisition leverage cannot support a security whose audited base and probability-weighted returns are negative even when the operating model is met. It identifies USD 5.962B of base terminal operating income as the most optimistic Stage 5 number because Calpine and corporate/unallocated RNF must normalize together. A 14% miss to modeled first-full-year Calpine RNF cuts EPS by about USD 1.17. The forced-exit signal is rolling-four-quarter Calpine RNF below USD 3.5B at the first complete ownership window, confirmed at the next quarterly update or hidden by an unreconciled taxonomy change.

Analyst flags

- Q2 FY2026 was after cutoff and is a later refresh trigger only.
- Calpine has 84 owned TTM days; full-year RNF and cash conversion are unproved.
- Contract economics, hedge coverage, acquisition ROIIC, and terminal claims are undisclosed; conclusions are constrained.

Appendix A - Company Primer

Constellation Energy Corporation — Institutional Company Primer

Information cutoff: 2026-08-06 09:02:30 SGT **Financial anchor:** TTM ended 2026-03-31; forward horizon 2031-03-31
Source discipline: Every financial-statement, segment-revenue, RNF, cash-flow, balance-sheet, debt, and share figure below comes from the QFR-sealed `quant_foundation.md`. Additional business context comes only from live Constellation investor-relations materials and live SEC filings retrieved for this run. Q2 FY2026 results were scheduled after the cutoff and are not used.

1. Business overview

Constellation is best understood as an integrated competitive power merchant, generator, and customer supplier rather than a regulated electric utility. It owns and operates generation, sells electricity and natural gas to wholesale and retail customers, procures energy when its customer obligations exceed its own production, and monetizes the environmental and reliability attributes of its fleet. Its legacy economic center is the largest U.S. nuclear fleet; the January 7, 2026 Calpine combination added a large dispatchable natural-gas and geothermal fleet, more retail load, and a much broader position in Texas, California, and the Northeast.

The customer set ranges from distribution utilities, municipalities, and cooperatives to commercial and industrial companies, public-sector entities, and households. Before Calpine, the company reported about 2 million customer accounts, including approximately 1.4 million residential accounts and three-fourths of the Fortune 100. The Q1 2026 investor materials describe the combined platform as serving approximately 2.5 million accounts and 80% of the Fortune 100. Customers typically buy through negotiated bilateral contracts, retail supply agreements, utility or governmental load auctions, wholesale market sales, and long-term power-purchase agreements, or PPAs. Large commercial customers may also buy renewable-energy certificates, emissions-free energy certificates, hourly carbon-free matching, demand-response services, and customized sustainability products.

The operating system has three mutually reinforcing pieces:

- **Physical generation.** Nuclear units produce high-volume, low-carbon baseload power; Calpine's combined-cycle and cogeneration plants dispatch when market prices justify their fuel and variable operating cost; geothermal, hydro, wind, solar, batteries, and peakers add geographic and temporal flexibility.
- **Commercial and retail load.** Contracted customer demand provides an outlet for generation and a source of retail margin. When load and owned output do not coincide by location or hour, Constellation buys or sells in wholesale markets.
- **Portfolio risk management.** The company uses bilateral contracts, exchange-traded instruments, fuel contracts, congestion products, capacity positions, and customer contracts to shape the price, volume, location, and timing of exposures.

Fact: The Q1 2026 Form 10-Q describes six reportable segments—Mid-Atlantic, Midwest, New York, ERCOT, Other Power Regions, and Calpine—and says the CEO evaluates the regional business primarily using RNF. The combined company described a roughly 55 GW fleet after the merger and required divestitures. **Investor interpretation:** Constellation is not a simple bet on wholesale electricity prices. It is a portfolio whose value depends on the spread between realized customer and market revenues and the cost of fuel, purchased power, capacity, environmental products, operations, financing, and outages. Integration should damp some exposures through diversification, but it also adds gas, heat-rate, dispatch, and leverage risks that were much smaller in legacy CEG.

2. Revenue architecture: geography first, technology second

The legal reporting segments are geographic for the legacy business because generation and customer activity settle in regional power markets with different energy, capacity, transmission, and environmental rules. Calpine is temporarily reviewed as a standalone sixth segment following the acquisition. FY2025 predates closing, so the Calpine segment is correctly zero in that fiscal year. The TTM column captures only the acquired period from January 7 through March 31, 2026—not a full year of Calpine.

Reporting component	FY2025 revenue ($mm)	FY2025 share of consolidated revenue	TTM revenue ($mm)	What it economically contains
Mid-Atlantic	6,487	25.4%	6,669	Eastern PJM generation and customer-facing activity
Midwest	5,804	22.7%	6,132	Western PJM and U.S. MISO activity outside MISO South
New York	2,190	8.6%	2,197	NYISO generation, retail, capacity, and state-support exposure
ERCOT	1,904	7.5%	1,876	Texas energy-market generation and customer activity
Other Power Regions	5,583	21.9%	5,514	New England, South, West, and Canada
Calpine	0	0.0%	2,395	Acquired gas, geothermal, other generation, and Calpine commercial activity
Other activities not allocated to a segment	3,565	14.0%	5,084	Natural gas and other energy-related sales, hedging marks, acquisition accounting, and non-segment items under issuer taxonomy
Consolidated	25,533	100.0%	29,867	GAAP operating revenue

The apparent precision of segment revenue can mislead. Power merchants often buy power and fuel and resell energy at large gross dollar values. A high-revenue region is not necessarily a high-profit region. In FY2025, New York produced only 8.6% of GAAP revenue but had a 73.1% RNF margin, while Other Power Regions produced 21.9% of revenue but had only a 14.7% RNF margin. These differences reflect the mix of generation, purchased power, fuel, customer sales, hedges, capacity, and state programs—not conventional product gross margins.

RNF versus GAAP revenue

RNF means **Operating revenues net of Purchased power and fuel expenses**. It is the issuer's segment performance measure and the cleanest first approximation of the economic value retained after acquiring the physical commodity sold to customers. It is not GAAP revenue, gross profit, adjusted EBITDA, or statutory operating income.

Bridge	FY2025 ($mm)	TTM ended 2026-03-31 ($mm)
Consolidated GAAP operating revenue	25,533	29,867
Consolidated RNF	10,852	13,218
Operating and maintenance	(6,159)	(6,394)
Depreciation and amortization	(985)	(1,180)
Taxes other than income taxes	(622)	(691)
Gain on sales of assets	—	14
Statutory operating income	3,086	4,967

Fact: RNF subtracts purchased power and fuel, while the remaining operating bridge still must absorb labor, maintenance, outage work, depreciation, property and other non-income taxes, and occasional gains. **Investor interpretation:** RNF is closer to an energy-portfolio contribution margin than an ordinary industrial gross margin. Forecasting GAAP revenue without separately forecasting purchased power and fuel is especially hazardous after Calpine, because gas prices and dispatched generation can inflate or deflate both lines without a proportional change in profit.

3. How a dollar becomes profit

Legacy nuclear and merchant generation

Nuclear plants are characterized by high sunk capital, substantial fixed operating and regulatory costs, relatively low variable fuel cost, and very high desired utilization. Once a unit is licensed, fueled, staffed, and maintained, each additional available megawatt-hour carries attractive incremental economics. Profit therefore depends heavily on realized power, capacity, and environmental-attribute revenue; operating reliability; outage duration; and the fixed-cost burden of the fleet.

Legacy CEG monetizes nuclear output through market sales, customer contracts, capacity auctions where applicable, state zero-emission or carbon-mitigation programs, federal nuclear production tax credits, and long-term PPAs. The federal nuclear PTC adds downside support for qualifying, non-state-supported units when gross receipts fall below an inflation-adjusted threshold, while leaving market upside above the phase-out. In the Q1 2026 presentation, management illustrated 2026 support of up to $15/MWh within a stated revenue band and no material Q1 PTC benefit because estimated full-year receipts for most units exceeded the phase-out. That creates a partial floor, not a fully guaranteed return: eligibility, unit-level gross receipts, tax rules, prevailing-wage compliance, program expiration after 2032, and political interpretation all matter.

Nuclear refueling concentrates maintenance and capital work into planned outages, generally on staggered multi-year cycles. A unit produces no electricity during the outage while labor and replacement-power costs rise. Constellation's advantage has been execution: the official 2025 Form 10-K reports capacity factors of 94.7%, 94.6%, and 94.4% in 2025, 2024, and 2023, respectively, and says performance has been about four percentage points above the industry average annually since 2013. Average refueling duration at operated units was 22 days in 2025. Q1 2026 was weaker at 92.3%, with 99 refueling-outage days versus 88 a year earlier, but no non-refueling outage days at operated sites.

Investor interpretation: A one-point capacity-factor change matters because it changes saleable output against a largely fixed cost base and may force replacement purchases for contracted load. Short refueling outages are therefore both an operating-quality signal and a recurring source of economic advantage. However, quarterly comparisons can be noisy because outage schedules deliberately move between periods.

Calpine gas, geothermal, and flexible generation

Gas economics are different. A combined-cycle plant runs when the power price exceeds the cost of natural gas adjusted for heat rate, variable operations, emissions, and other dispatch costs. That net is the spark spread. Efficient plants, advantaged gas supply, favorable locations, and high reliability expand the hours in which dispatch is economic. Peakers may run fewer hours but earn scarcity, capacity, ancillary-service, or reliability value. Cogeneration can also sell steam or useful heat to industrial hosts.

The acquired fleet adds large positions in ERCOT, CAISO, and the Northeast, as well as the Geysers geothermal complex. Management's Q1 2026 operating slide reported a 47.1% capacity factor and 5.1% equivalent forced-outage factor for the covered combined-cycle and cogeneration fleet, excluding assets pending divestiture. Unlike nuclear capacity factor, gas capacity factor reflects both availability and a commercial decision to dispatch; lower utilization can mean weak spreads rather than poor operations. EFOF is therefore the cleaner reliability indicator.

Geothermal generation offers carbon-free, around-the-clock output but carries reservoir-management, maintenance, and site-specific risks. Batteries and flexible gas units help the portfolio manage intraday price shape and renewable intermittency in California and Texas. The Calpine combination therefore changes Constellation from a predominantly nuclear merchant into a barbell: high-capacity-factor nuclear generation plus dispatchable gas and storage that can respond to system conditions.

Retail and commercial supply

Retail economics are the contracted selling price minus the cost to serve each customer's actual hourly load. Cost to serve includes energy, capacity where applicable, ancillary services, transmission and congestion, environmental compliance products, credit, and customer acquisition and service. Weather, customer usage, price shape, basis, and load forecasting can all make actual procurement costs diverge from the assumptions embedded in a fixed-price contract.

Owned generation is not automatically matched to retail customers. A nuclear megawatt-hour in one node and hour cannot satisfy load in another without market and transmission exposure. The combined portfolio nevertheless improves the opportunity for physical and commercial offsets. At announcement, management said Calpine contributed roughly 59 TWh of annual retail load and a customer base weighted toward commercial and industrial accounts. The stated strategic logic was to use dispatchable assets to support more load with less dependence on supplemental market products, cross-sell gas to power customers, and sell Constellation's premium clean-energy products through a larger channel.

Investor interpretation: This can increase commercial margin and reduce gross commodity risk, but it is not a free natural hedge. The value depends on location, hour, product, contract tenor, credit quality, and portfolio execution. Winter Storm Fern in Q1 2026 was an early reminder: higher capacity revenue was partly offset by a higher cost to serve load.

4. The completed Calpine combination

Constellation closed Calpine on January 7, 2026. The quantitative foundation records approximately 50 million CEG shares issued, $4.342 billion of cash consideration, and a $17.603 billion fair value assigned to the share consideration. The transaction lifted period-end shares from 312 million at FY2025 to 362 million at Q1 2026 and gross debt from $8.992 billion to $22.466 billion. Cash-only net debt reached $21.666 billion at March 31, 2026.

Strategically, the combination added approximately 23 GW across 72 generation and battery assets after contemplated regulatory divestitures. It also moved the generation footprint away from legacy concentration in PJM. The acquisition presentation showed a pro forma 2023 generation mix of roughly 49% PJM, 23% ERCOT, 10% CAISO, 8% NYISO, and 10% other markets, compared with 69% PJM for standalone Constellation. Those are management-presented operational mix statistics, not segment financials, but they capture the diversification logic.

The benefits are tangible:

- gas generation provides dispatchable reliability as intermittent renewable penetration rises;
- California geothermal supplies scarce 24/7 carbon-free output;
- powered land beside existing plants can shorten the path to serving very large data-center loads;
- a broader retail book can absorb more generation and support cross-selling;
- geographic diversity reduces dependence on a single market design or weather pattern.

The costs and risks are equally tangible:

- the balance sheet is materially more leveraged;
- gas generation adds fuel, heat-rate, emissions, and environmental-policy exposure;
- purchase accounting introduces amortization of acquired commodity contracts and can widen the gap between GAAP and adjusted results;
- integration must combine risk systems, retail books, plant cultures, and credit arrangements without losing commercial discipline;
- DOJ and FERC remedies require asset sales, so the final portfolio and earnings base differ from the headline acquired fleet.

Management originally described a focused plan to return to target credit metrics within two years, using cash generation and refinancing to retire higher-coupon Calpine debt. Q1 2026 still carried BBB+/Baa1 senior unsecured ratings with stable outlooks. The key investor issue is not whether the acquisition is optically accretive; it is whether free cash flow after maintenance, nuclear fuel, growth capital, integration costs, collateral, and dividends is sufficient to reduce leverage while management also pursues buybacks and growth.

5. Customers, contracts, and PPAs

The contract spectrum runs from short wholesale trades to multi-decade nuclear PPAs. Each transfers a different mix of price, volume, basis, shape, outage, credit, and regulatory risk.

Contract or channel	Typical customer/value proposition	Economic effect for CEG	Principal residual risks
Retail fixed or structured supply	C&I, public sector, residential	Commercial margin and outlet for portfolio supply	Load shape, weather, basis, credit, procurement cost
Wholesale bilateral or auction sale	Utilities, municipalities, cooperatives	Locks output or meets buyer procurement needs	Counterparty, volume, congestion, collateral
RTO/ISO market sale	Regional spot and forward markets	Monetizes uncontracted generation and flexibility	Commodity price, nodal basis, negative prices
Capacity commitment	PJM, NYISO, ISO-NE, MISO markets	Pays for dependable availability	Auction design, performance penalties, accreditation
Clean-energy attribute sale	Corporates and public-sector buyers	Premium for emissions-free or renewable characteristics	Certification, additionality standards, policy change
Long-term PPA	Hyperscalers and utilities	Long-duration revenue visibility supporting life extension or new capital	Customer concentration, project execution, regulatory approvals

Two nuclear agreements illustrate the strategic direction. The 20-year Microsoft PPA supports the restart of the 835 MW Crane Clean Energy Center and is intended to match power used by Microsoft data centers in PJM with carbon-free energy. The 20-year Meta agreement covers the 1,121 MW Clinton facility beginning in 2027, supports continued operation after the Illinois ZEC program ends, and includes a 30 MW uprate. These contracts convert part of a merchant or policy-supported nuclear asset into a long-duration corporate-backed stream while preserving power delivery through the grid rather than a simplistic dedicated wire.

Calpine adds another model: **powered land**. In Q1 2026, the company disclosed a 380 MW agreement with CyrusOne beside the Freestone Energy Center in Texas, plus exclusivity for another 380 MW phase. The offering combines land, grid connectivity, infrastructure, and power access. It can monetize scarce interconnection and site readiness, but the PUCT approval was subject to conditions and similar projects remain exposed to market-rule and cost-allocation decisions.

6. Regional market exposure

PJM and the Mid-Atlantic/Midwest

PJM is the largest legacy exposure and remains central after Calpine. Generation earns energy and capacity revenue; retail load incurs energy and capacity cost; nuclear units may also earn environmental or federal support. PJM capacity auction prices rose sharply in 2025, benefiting generation but also increasing the cost to serve load. Large data-center interconnections are stressing load forecasts and capacity procurement. FERC's 2025 co-location order and PJM's evolving reliability-backstop framework show that the rules for allocating transmission, capacity, and reliability costs to large loads are not settled.

ERCOT

ERCOT has no centralized capacity market. Economics lean more heavily on energy prices, scarcity, bilateral contracts, ancillary services, plant location, and operational responsiveness. This creates higher volatility but also rewards flexible gas units during tight conditions. Calpine materially expands CEG's Texas generation and retail presence and enables powered-land projects. Pin Oak, a 460 MW peaker that reached commercial operation after quarter-end, and the Freestone/CyrusOne arrangement illustrate the opportunity. The corresponding risks are gas-basis moves, severe weather, transmission congestion, rapid load growth, and state intervention in market design.

CAISO and the West

Calpine gives Constellation a major California position through efficient gas plants, geothermal, solar, and storage. CAISO needs flexible resources to balance solar-heavy supply, steep evening ramps, and resource-adequacy requirements. Gas and batteries can monetize flexibility; geothermal offers scarce firm carbon-free power. Yet California also presents emissions regulation, permitting constraints, wildfire and water considerations, and policy uncertainty over the long-run role of gas.

New York and other markets

NYISO includes nuclear, capacity, retail, and ZEC exposure. Other Power Regions span ISO-NE, the South, the West, and Canada. ISO-NE capacity payments and gas-delivery constraints can make winter reliability valuable; MISO combines nuclear generation and state support with region-specific capacity rules. Diversity helps, but every ISO/RTO has distinct settlement, accreditation, congestion, and policy regimes, making commercial systems and regulatory expertise core capabilities.

7. Commodity exposure and hedging

Constellation's filings say it generally concentrates portfolio hedging in the prompt three years, when customer demand and market liquidity make hedging most effective. It uses customer sales, bilateral transactions, exchange products, fixed-price fuel and power contracts, and congestion instruments. Nuclear fuel is procured predominantly through long-term uranium, conversion, enrichment, and fabrication arrangements; the company diversifies suppliers and holds inventory across multiple years. Gas is procured through long- and short-term contracts, transportation arrangements, and spot purchases.

Hedging changes the timing and accounting presentation of risk rather than eliminating it. GAAP requires most derivatives to be marked through earnings, creating unrealized gains or losses that can reverse before settlement. Some qualifying normal-purchase/normal-sale contracts are recognized as physical delivery occurs. Collateral requirements can consume liquidity when forward prices move even if the underlying economic position is sound. A downgrade below investment grade would have required an estimated $3.0 billion of incremental collateral at the Q1 anchor; disclosed available credit capacity of

$6.682 billion plus $800 million of cash provided coverage, but not unlimited comfort.

The nuclear PTC, state programs, retail load, and long-term PPAs create layers of downside protection. Calpine gas units add a different hedge because power prices often rise with gas prices, although heat rates, gas basis, and local congestion can break that relationship. The remaining uncontracted book retains upside and downside to power prices, capacity prices, spark spreads, volatility, and operational performance.

8. Data-center and AI power demand

AI is a demand driver, not a separate accounting segment. Hyperscalers seek large, reliable, fast-to-connect power blocks and increasingly want hourly carbon-free matching. Constellation owns three scarce ingredients: existing nuclear output, dispatchable gas capacity, and sites with grid interconnections. Management's Q1 presentation showed 147 million MWh of expected 2029 baseload clean generation supported by the PTC or available for long-term agreement, and highlighted 5,000 MW of potential new PJM capacity submissions. These are opportunity-set disclosures, not contracted earnings.

The investment case has three paths. First, PPAs can preserve or restart nuclear assets and attach a premium to clean reliability, as with Microsoft/Crane and Meta/Clinton. Second, uprates and license extensions can add output faster and at lower system cost than greenfield nuclear. Third, powered-land deals can monetize existing generation, interconnection rights, and sites for gas-backed data centers.

Inference: Demand growth should improve bargaining power for reliable generation, but the value will accrue only if regulators permit cost allocation, transmission and interconnection work is completed, customers sign bankable contracts, and CEG avoids overbuilding to speculative load forecasts. AI demand therefore raises both the ceiling and the capital-at-risk.

9. Capital intensity, debt, and deleveraging

This is a capital-intensive business even before growth. FY2025 capital expenditure was $2.949 billion and TTM capex was $3.418 billion. TTM operating cash flow of $4.555 billion less capex produced only $1.137 billion of simple FCF, despite $3.791 billion of common net income. The gap reflects working capital, collateral, outage timing, acquisition effects, and heavy investment requirements. Historical OCF was negative in 2023 and 2024 under the issuer's reported cash-flow presentation because collateral and working-capital movements were large; investors should not normalize these away without understanding the cash mechanics.

At March 31, 2026, gross debt was $22.466 billion and cash-only net debt was $21.666 billion. The company also had $5.102 billion of short-term borrowings. This makes financing, collateral, and refinancing costs meaningful components of equity value. The combination creates more cash-generating assets, and required divestitures should provide proceeds, but deleveraging competes with dividends, buybacks, nuclear life extensions, the Crane restart, gas and storage additions, and integration spending.

Investor interpretation: Management's investment-grade target is credible only if cash conversion improves on a sustained basis. A useful discipline is to track gross debt and cash-only net debt, not a vendor net-debt figure that subtracts restricted cash; compare debt reduction with asset-sale proceeds; and treat buybacks as residual rather than automatically accretive while leverage remains elevated.

10. Regulation and competitive landscape

Constellation operates at the intersection of nuclear safety regulation, wholesale market design, retail choice, environmental law, tax policy, and antitrust enforcement.

- **Nuclear:** The NRC controls operating licenses, restart approvals, inspections, security, spent-fuel handling, and decommissioning. License extensions and uprates are valuable but require long lead times and capital. Crane still requires regulatory and interconnection execution.
- **Wholesale markets:** FERC oversees market-based rates and RTO/ISO tariffs. Capacity mitigation, price caps, co-location rules, accreditation, and transmission cost allocation can materially change both generation revenue and retail cost.
- **State policy:** Illinois CMC/ZEC programs and New York ZECs support selected nuclear units; renewable and clean-energy standards create compliance demand. Programs can expire, be redesigned, or face legal challenge.
- **Gas and environmental rules:** Calpine plants face air permits, emissions programs, water constraints, gas transportation, and changing state decarbonization policy.

- **Antitrust:** FERC and DOJ required divestitures after the Calpine deal, demonstrating that market concentration can constrain portfolio optimization.

Competitors include merchant generators such as Vistra and NRG, renewable and regulated-utility owners such as NextEra, independent gas and storage developers, retail suppliers, utilities procuring on behalf of customers, and energy majors active in gas and power marketing. Constellation's differentiation is not merely fleet size. It is the combination of high-performing nuclear operations, dispatchable gas and geothermal scale, a national C&I customer channel, commodity risk infrastructure, investment-grade access to collateral and financing, and the ability to package energy with reliable clean attributes.

The vulnerabilities mirror those strengths: complex hedging can obscure exposure; capital intensity and leverage reduce flexibility; nuclear events are low-frequency but severe; retail margins can be competed away; gas assets face decarbonization risk; and market rules can reallocate value between generators, loads, and consumers.

11. What an institutional investor should monitor

- **Nuclear availability:** capacity factor, non-refueling outage days, refueling duration, and replacement-power effects.
- **Calpine reliability and dispatch:** EFOF, gas capacity factor, spark spreads, and asset-divestiture completion.
- **Commercial quality:** retail load, margin per MWh or dekatherm, customer retention, and cost-to-serve under extreme weather.
- **Contract conversion:** how much available nuclear and powered-land opportunity becomes signed, creditworthy, long-duration revenue.
- **Debt and liquidity:** gross debt, cash-only net debt, short-term borrowings, collateral utilization, ratings, and refinancing costs.
- **Accounting bridge:** GAAP revenue to RNF to operating income, including hedge marks and acquired-contract amortization.
- **Policy:** nuclear PTC implementation and expiry, state support transitions, PJM large-load rules, ERCOT cost allocation, and NRC approvals.

The core thesis is that scarce, reliable generation and a broad customer platform can monetize structural load growth. The core counter-thesis is that commodity exposure, regulatory intervention, acquisition leverage, and capital needs absorb much of that scarcity value before it reaches equity holders. The primer should therefore orient the reader toward RNF, operating performance, cash conversion, and leverage—not headline GAAP revenue or megawatts alone.

Primary qualitative sources

- Constellation, [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm), Item 1, Item 7, and Note 5, live-retrieved 2026-08-06.
- Constellation, [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm), Notes 2 and 5 and MD&A, live-retrieved 2026-08-06.
- Constellation, [Q1 2026 earnings presentation](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000063/ceg-20260511992.htm), May 11, 2026.
- Constellation, [Calpine acquisition presentation](https://www.sec.gov/Archives/edgar/data/1168165/000186827525000006/ceg-202501108kxexh992.htm), January 10, 2025.
- Constellation, [Microsoft/Crane 20-year PPA announcement](https://www.constellationenergy.com/news/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html), September 20, 2024.

- Constellation, [Meta/Clinton 20-year PPA announcement](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-meta-sign-20-year-deal-clean-reliable-nuclear), June 3, 2025.
- Constellation, [Q1 FY2026 results release](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-reports-first-quarter-2026-results), May 11, 2026.

Appendix M - Management Assessment

Constellation Energy Corporation — Management Assessment

Information cutoff: 2026-08-06 09:02:30 SGT. The financial anchor is Q1 FY2026/TTM ended 2026-03-31. Q2 FY2026 evidence is excluded. **Management gate: YELLOW** — investable leadership and excellent nuclear stewardship, but the $21.835 billion closing-date Calpine consideration, associated leverage, and integration are not yet seasoned enough to establish decade-grade capital-allocation skill.

1. Who is running the company

Joe Dominguez has been president and CEO since Constellation separated from Exelon in February 2022. He had already led Exelon Generation in 2021-2022, after running ComEd from 2018-2021 and earlier serving in senior policy, regulatory, and legal roles. He therefore owns the post-separation strategy, including the nuclear production-tax-credit positioning, long-term nuclear offtakes, Crane restart, and Calpine acquisition—not merely its inherited execution. [The 2026 proxy biography](https://www.sec.gov/Archives/edgar/data/1868275/000155278126000140/e26004_ceg-def14a.htm) describes his operating remit and pre-Constellation roles.

The finance structure changed at the Calpine close. Shane Smith became EVP and CFO on January 7, 2026 after serving as treasurer and SVP of Treasury and Credit; he reports to Dan Eggers, now Senior EVP, Finance and Data Economy. Eggers was CFO from separation through the Calpine closing and remains the senior executive accountable for finance and data-economy contracting. This preserves deal knowledge, but the nonstandard CFO-to-former-CFO reporting line can blur accountability if Calpine or customer contracts underperform. Smith's long history in treasury, credit, and transactions is fit for the deleveraging phase. [The 2025 10-K executive table](https://investors.constellationenergy.com/static-files/f1b13793-e918-4e20-9a4c-4cda86c916a3) and [leadership-change release](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-announces-key-senior-leadership-changes-ahead) establish the roles.

The other load-bearing leaders are Andrew Novotny, Senior EVP of Constellation Power Operations and president/CEO of Calpine; Bryan Hanson, Senior EVP and Chief Generation Officer; and Jim McHugh, Senior EVP and Chief Commercial Officer. Novotny led Calpine from 2024 and was its COO from 2021, providing continuity. Hanson owns nuclear stewardship; McHugh owns retail, wholesale, innovation, and commercial contracting.

Robert Lawless is independent board chair. The board had 12 directors at the 2026 proxy date, 11 independent and only Dominguez non-independent. Tenure is not entrenched: the longest current service begins in 2022, with later additions including Alan Armstrong and Eileen Paterson. The board became fully declassified after the 2026 annual meeting. Its separate Nuclear Oversight Committee met four times in 2025, including plant-site meetings. No director was outside the disclosed public-board service policy; a few sit at the three-board ceiling, which merits workload monitoring but is not an overboarding breach.

2. Tenure and track record

Dominguez has enough tenure to own results but not yet the five-plus-year proof required for an unqualified Gideon PASS. His three largest decisions are measurable:

Decision	Year and capital at risk	Observable result through cutoff	Assessment
Establish the independent-company operating and capital-return model	2022	From FY2022-FY2025, capex rose from $1.689B to $2.949B; post-spin buybacks totaled about $4.14B; the 2026 proxy reports approximately 634% TSR from separation through 2025	Strong per-share and operating outcome, albeit aided by nuclear policy and power-market re-rating
Contract and restart Crane Clean Energy Center	2024; approximately $1.6B restart capex	20-year Microsoft PPA supports 835 MW; DOE supplied a $1B interest-bearing loan; restart work was ahead of the initial 2028 schedule but had not reached commercial operation	Strategically coherent and contract-backed; final cost, NRC approval, and operating return remain unproven

Decision	Year and capital at risk	Observable result through cutoff	Assessment
Acquire Calpine	Signed 2025; closed 2026	Original equity value was about $16.4B and effective enterprise purchase price $26.6B; closing-date merger consideration was $21.835B before assumed debt; Q1 guidance retained roughly $2 EPS accretion	Transformational but too early to call value-creating; this is the gate's main unresolved issue

The separation-era nuclear record is excellent. Capacity factor was 94.4% in 2023, 94.6% in 2024, and 94.7% in 2025; Constellation says its fleet has run roughly four percentage points above industry annually since 2013. Average 2025 refueling outage duration was 22 days versus industry experience of 33 days in 2024 and 38 days in 2023. Q1 2026's 92.3% factor reflected a heavier planned-refueling schedule, while the acquired combined-cycle/cogeneration fleet delivered when dispatched about 95% of the time. [The 2025 10-K](https://investors.constellationenergy.com/static-files/f1b13793-e918-4e20-9a4c-4cda86c916a3) and [Q1 2026 release](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-reports-first-quarter-2026-results) support those metrics.

There is no obvious post-spin write-off to use as a clean failure case. The better skeptical test is how management handles incomplete disclosure or friction. In Q1 2026 Dominguez acknowledged that the March free-cash-flow presentation could have been better and added a 2028-2029 range. Regulatory remedies for Calpine became sizable—about 4.4 GW of PJM gas assets agreed for sale to LS Power for $5B, plus other required interests—but management had flagged limited asset sales at signing, and the price appears constructive. This is a qualified correction, not concealment.

3. Capital allocation behavior

The permitted data-package record shows a coherent transition from separation to reinvestment and then balance-sheet repair.

FY	Capex ($B)	Buybacks ($B)	Dividends ($B)	M&A net cash-flow line ($B)
2021	1.329	0.064	1.832	1.329
2022	1.689	1.750	0.185	0.052
2023	2.422	0.992	0.366	0.024
2024	2.565	0.999	0.444	(0.032)
2025	2.949	0.400	0.486	(0.014)

FY2021 and FY2022 contain separation effects, and the cash-flow M&A line is not acquisition consideration. R&D is not separately disclosed. Post-spin behavior has otherwise been sensible: invest in fleet reliability and uprates, raise the dividend, repurchase stock, and slow repurchases while financing Calpine.

Buybacks show some price sensitivity. The company repurchased about $1B in each of 2023 and 2024, only $400M in 2025 during transaction preparation, then bought 1.2M shares around $285 in spring 2026 and 2M secondary shares at $281 in June. That is more deliberate than a mechanical quarterly program. However, management issued 50M fixed shares for Calpine using an announcement reference value near $237.98, while the closing-date fair value of those shares reached $17.603B. Repurchasing part of the dilution above $280 does not erase the fact that the economic value transferred to sellers rose materially before close.

Calpine's financing is the decisive test. At close Constellation paid $4.342B cash and issued shares worth $17.603B; it assumed about $12.6B debt, including $7.6B corporate and $5.0B project financing. It then repaid $2.5B corporate term loans at close, $1.25B secured notes in February, and $1.4B unsecured notes in March. Q1 gross debt was $22.466B and cash-only net debt $21.666B. Management plans $3.4B of further deleveraging by end-2027 and targets Baa1/BBB+ metrics. This is credible but not completed. The original [Calpine announcement](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-acquire-calpine-creates-americas-leading-producer) advertised 7.9x 2026 EV/EBITDA, over 20% 2026 EPS accretion, at least $2 EPS thereafter, and more than $2B annual FCF; all depend on adjusted forecasts, tax attributes, and successful integration.

Contracting supports the strategy. The [Microsoft PPA](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-launch-crane-clean-energy-center-restoring-jobs) backs 835 MW at Crane for 20 years; the [Meta PPA](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-meta-sign-20-year-deal-clean-reli

able-nuclear) covers Clinton's 1,121 MW output from June 2027 plus a 30 MW uprate; and [CyrusOne](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-and-cyrusone-announce-agreement-support-new-data) contracted 380 MW at Freestone with an exclusive additional 380 MW phase. These are strategically valuable, but price and project-level returns are confidential. Investors cannot independently verify management's claimed double-digit unlevered-return threshold.

4. Compensation alignment

The 2025 CEO target package was $16.0M: $1.5M salary, a 160% annual-incentive target, and $12.1M LTI. About 91% was variable. LTI was 33% time-based RSUs and 67% performance shares. Performance shares use three-year free cash flow before growth (67%) and relative TSR (33%), with a negative credit-rating modifier. This is better than revenue- or scale-only pay, and Calpine-related FCF targets were raised rather than leaving an acquisition windfall. Clawbacks cover restatements and broader misconduct; hedging, pledging, short sales, and derivatives are prohibited.

The weaknesses matter. There is no explicit ROIC or post-acquisition return metric. Compensation FCF excludes growth capex, working-capital effects, and other adjustments approved by the committee; targets are disclosed only after the cycle. The 2023-2025 performance-share award paid 200% of target, partly reflecting a remarkable stock re-rating, before Calpine had to prove its return. That structure may reward TSR optics and adjusted cash generation while underweighting the price paid for growth.

Dominguez was reported with 121,360 directly owned common shares after his February 2026 award settlement and tax withholding. The proxy's 157,074 beneficial-ownership figure is not an all-cash-at-risk number because it includes RSUs, deferred units, and cash-settled phantom shares. The ownership policy is six times salary for the CEO and three times for other NEOs, but it also counts unvested RSUs. Alignment is meaningful, not perfect.

Stock-based compensation rose from $47M in 2021 to $116M in 2022, $178M in 2023, $332M in 2024, and $385M in 2025—approximately 0.2%, 0.5%, 0.7%, 1.4%, and 1.5% of revenue, respectively. The rise reflects share-price-sensitive awards and is noticeable, but still below chronic-dilution territory; many performance awards are partly or wholly cash-settled once ownership thresholds are met. [The 2022](https://investors.constellationenergy.com/static-files/9e7b2586-3b65-4ccc-8bd9-fddfed733a9d) and [2025 10-Ks](https://investors.constellationenergy.com/static-files/f1b13793-e918-4e20-9a4c-4cda86c916a3) provide the five-year series.

5. Disclosure quality and candor

I reviewed the eight most recent live FMP transcripts available through the cutoff: Q1-Q3 2024, Q1-Q4 2025, and Q1 2026. FMP returned an empty object for Q4 2024, so the official February 18, 2025 release was used for that missing fiscal period. No cached transcript was used.

Management usually answers numbers directly when it can: buyback price and shares, Calpine lockup dates, long-run roughly 2x debt/EBITDA, the absence of buyback accretion from the base EPS CAGR, and the components behind low near-term FCF conversion. Guidance discipline is strong: 2024 adjusted EPS of $8.67 exceeded the $8.00-$8.40 twice-raised range, 2025's $9.39 exceeded the initial midpoint, and management said it had beaten the midpoint in all four public-company years. Q1 2026 affirmed $11-$12.

Hedge markers such as “headwind,” “uncertainty,” “pause,” “clarity,” “conservative,” or “complicated” appeared in management answers in seven of eight reviewed transcripts. The concentration was highest in Q1 2025, Q4 2025, and Q1 2026, when PJM rules and Calpine integration were genuinely unresolved. Most uses were tied to a named docket, customer decision, or timing dependency—not euphemisms for a shrinking business. Still, management withholds contract prices, FCF compensation targets, project returns, and hyperscaler timing. On a tough Q4 2025 question about why 2026-2027 FCF looked low, Smith named integration costs and maintenance capex but did not quantify either. Disclosure is above average operationally, only average on acquisition economics.

6. Strategic coherence

The 2026 proxy describes the company as building “clean, reliable energy capacity” while meeting current demand. Investment matches that claim: nuclear life extension and uprates, Crane restart, Calpine's flexible gas/geothermal fleet, a national commercial platform, and long-duration customer contracts. This is not a sequence of unrelated pivots. Calpine is a major broadening from near-zero-carbon generation into gas, but it is coherent with the stated reliability and data-economy strategy.

Management also names competitive and regulatory constraints directly: PJM interconnection, FERC co-location rules, capacity adequacy, data-center curtailment, gas build economics, NRC approvals, and customer affordability. The strategic risk is not incoherence; it is overconfidence. Frequent “unmatched,” “best,” and 20%-plus growth framing can outrun the evidence when contract economics are undisclosed and Calpine integration has only one reported quarter.

7. Governance flags

The proxy disclosed no related-person transactions in 2025. Constellation has one common share class, no controlling shareholder, and no dual-class minority-shareholder problem. Former Calpine owners initially held about 14% with phased lockups, but no disclosed control rights. Eleven of 12 directors are independent; the chair is independent; and annual elections now apply to the full board.

The reviewed filings disclosed no SEC enforcement, restatement, or material weakness. Management and the auditor concluded internal controls were effective at year-end 2025. Q4 2025 and Q1 2026 filings reported no director or executive adoption or termination of Rule 10b5-1 arrangements. The Form 4 activity reviewed around February 2026 was vesting, withholding, and award settlement rather than a clustered discretionary exit. The principal governance concern is incentive design—not self-dealing or control.

8. Peer comparison

CEO	Capital allocation and communication	Relative ranking to Dominguez
Jim Burke, Vistra	Energy Harbor integration, about $6.3B of repurchases since 2021 by Q1 2026, sub-3x leverage discipline, and multiple contracted nuclear/gas investments provide more completed acquisition proof	Better five-year allocator today; similarly transparent operationally
Mac McFarland, Talen	Sold ERCOT assets, repurchased 22% of shares in 2024, expanded the Amazon PPA, then re-levered for gas acquisitions; disclosure is explicit but the post-bankruptcy record is shorter and more concentrated	Comparable strategic boldness; Dominguez has stronger operating-platform proof, McFarland stronger near-term per-share return evidence
Robert Gaudette, NRG	Became CEO April 30, 2026 after the $12B-class LS Power portfolio close; inherited a defined $1B 2026 repurchase plan but has almost no in-seat record	Dominguez clearly ahead on tenure and operating stewardship

On a five-year stewardship basis, Dominguez ranks behind Burke, ahead of Gaudette, and roughly level with McFarland after adjusting for Talen's shorter public history. Constellation communicates nuclear operations better than peers, but Vistra currently offers the cleaner precedent that a large fleet acquisition can integrate while leverage falls and buybacks continue.

9. Verdict on the management gate

YELLOW. Dominguez and the separation-era team have earned credibility through exceptional nuclear operations, repeated guidance delivery, coherent long-term contracting, price-aware repurchases, and clean minority-shareholder governance. They have not yet earned a PASS because the fixed-share Calpine consideration rose materially by closing, debt is elevated, integration has only one reported quarter, and compensation omits explicit ROIC while relying heavily on adjusted FCF and TSR. A FAIL is not justified: there is no evidence of serial value-destructive M&A, chronic dilution, evasive guidance, related-party behavior, or operating neglect.

Upgrade to **PASS** only if all three conditions are met: (1) by end-2027, at least $3.4B of deleveraging is completed while Baa1/BBB+ metrics are preserved; (2) Calpine demonstrably supplies at least the promised approximately $2 annual EPS accretion and more than $2B annual FCF without recurring “integration” adjustments or nuclear reliability slippage; and (3) Crane, Meta, CyrusOne, and follow-on contracts show bounded capital needs and credible double-digit unlevered returns. Downgrade to **FAIL** if Calpine requires repeated target resets, leverage remains structurally above the stated approximately 2x framework after asset-sale proceeds, or management continues buybacks while integration cash conversion misses and project economics remain opaque.

Source-control note

Primary evidence was retrieved live before the cutoff from the [2026 proxy](https://www.sec.gov/Archives/edgar/data/1868275/000155278126000140/e26004_ceg-def14a.htm), [2025 10-K](https://investors.constellationenergy.com/static-files/f1b13793-e918-4e20-9a4c-4cda86c916a3), [Q1 2026 10-Q](https://www.sec.gov/Archives/edgar/data/1168165/000186827526000067/ceg-20260331.htm), official IR releases, and

FMP's live stable transcript endpoint. Capital-allocation history and corporate-action chronology came from `data_package.md` Sections 7 and 9 as instructed. Live transcript JSON and the empty Q4 2024 response are preserved under `raw/pulse-cio-20260806T090230+0800/M/`; new copies were saved to the investing data warehouse without overwriting existing files.

Appendix W - Moat and 2046 Durability

Constellation Energy Corporation — Moat and 2046 Durability

Run: `pulse-cio-20260806T090230+0800` **Information cutoff:** 2026-08-06 09:02:30 SGT **TTM anchor:** Q2 FY2025 through Q1 FY2026, ended 2026-03-31 **Five-year model horizon:** 2031-03-31 **Twenty-year test date:** 2046-08-06 **Assessment basis:** The verified [production data package](C:/Users/Admin/OneDrive/GPT/ER%202.0/Constellation%20Energy%20Corporation/data_package.md), current segment appendices, live official filings, and regulator/company primary sources. RNF means the issuer's exact segment metric, **Operating revenues net of Purchased power and fuel expenses**; it is not statutory operating income.

1. Moat taxonomy applied

Network effects — absent. More generators or retail customers do not make Constellation's product inherently more valuable to every other customer. A larger portfolio can improve risk netting, procurement, and product breadth, but that is a scale economy, not a self-reinforcing network. RTO/ISO participation is an industry network that all qualified rivals can access. Investors should assign no network-effect premium.

Switching costs — uneven and mostly contractual. Ordinary retail electricity and gas supply has low-to-moderate switching costs: sophisticated commercial customers can rebid supply, and Constellation's own 2025 Form 10-K says retail barriers to entry can be low. The stronger lock-in exists in tailored, long-duration arrangements where generation, clean attributes, hourly matching, grid connectivity, land, interconnection work, credit support, and project capital are bundled. Microsoft/Crane and Meta/Clinton each run for 20 years; CyrusOne's Freestone arrangement combines power, site infrastructure, and grid connectivity. These are real contractual switching costs once operational, but they attach to a minority of the fleet, contract pricing is confidential, and project or regulatory failure can prevent the lock-in from forming.

Scale economies — strong in nuclear operations and commercial risk infrastructure; moderate elsewhere. Constellation operates the largest U.S. nuclear fleet and combines specialized outage planning, fuel procurement, NRC compliance, security, engineering, and a national customer/risk platform across many units. The fleet sustained 94.4%-94.7% annual capacity factors in FY2023-FY2025, about four percentage points above the industry average annually since 2013 according to the [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). That repeatable operating spread is the best observable moat evidence. Calpine adds approximately 23 GW after contemplated divestitures, flexible gas, storage, and a 725 MW geothermal complex; scale helps but does not immunize gas assets from spark spreads or retail from price competition.

Brand — useful in high-trust procurement, weak in commodity supply. The Constellation name matters to hyperscalers, public entities, and Fortune 100 buyers that need credible 20-year performance, environmental attributes, collateral, and regulatory execution. Brand probably lowers customer-acquisition friction and supports permission to bid on complex contracts. It does not let Constellation charge a durable premium for an undifferentiated MWh in an RTO auction or a standard retail contract.

Regulatory position — strong barrier, double-edged economics. NRC licenses, plant-specific safety systems, trained workforces, security, decommissioning obligations, environmental permits, market-based-rate authority, interconnection rights, and RTO qualification make the physical fleet extremely difficult to replicate. The NRC defines subsequent license renewal as extending operation from 60 to 80 years and, as of July 2026, was reviewing Constellation's Nine Mile Point Unit 1 application while listing further Constellation applications in its pipeline ([NRC status](https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal)). Yet the regulator can also cap, reallocate, or destroy rent. FERC can change market rules, states can change ZEC/CMC programs, the NRC can delay a restart or renewal, and antitrust remedies have already required post-Calpine asset sales. Regulation protects incumbency but does not guarantee shareholder returns.

IP and patents — not a material moat. Constellation does not own a proprietary reactor design, fuel cycle, gas-turbine platform, or retail software monopoly. Its know-how is embedded in procedures, operating history, risk systems, workforce, and regulatory credibility. That tacit operational knowledge is hard to copy quickly, but it is better classified as scale, organizational capability, and high-trust procurement than formal IP.

High-trust procurement — strong for nuclear and large-load solutions. A buyer committing data-center power demand for 20 years cares about counterparty credit, delivery, regulatory competence, outage management, and the ability to finance billions of dollars. Microsoft's 20-year PPA supports an approximately 835 MW Crane restart ([official announcement](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-launch-crane-clean-energy-center-restoring-jobs)); Meta's 20-year PPA covers 1,121 MW at Clinton from June 2027 and replaces an expiring state ZEC program ([official announcement](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-meta-sign-20-year-deal-clean-reliable-nuclear)). Few counterparties can offer this combination. The moat is the scarce asset plus permission and execution, not the contract document alone.

2. Per-segment moat

Segment	Defensible profit pool	Durability	What breaks it	Earliest observable sign
Mid-Atlantic	Large nuclear fleet, hydro/pumped storage, scarce PJM interconnections, operating record, capacity and customer platform	Strong 5-10 year; conditional 20 year	Adverse PJM market design, license/restart failure, prolonged outages, or hyperscaler projects losing economics	Capacity-factor decline; Crane schedule slip; adverse FERC/PJM cost-allocation order; RNF margin below prior troughs
Midwest	Largest TTM RNF pool; high-performing Illinois nuclear fleet; Clinton/Meta contract; capacity and clean attributes	Strong 5-10 year; credible but renewal-dependent 20 year	PPA counterparty/project issues, NRC non-renewal, post-PTC merchant weakness, negative-price cannibalization	Meta/Clinton milestone miss; rising outage days; RNF margin below roughly 55%; renewal delays
New York	Nuclear scarcity, NYISO capacity, four-unit cluster, and adopted ZEC 2.0 support through 2049	Strong 5-10 year; conditional 20 year	Failure to renew NMP1/Ginna/FitzPatrick, periodic ZEC review, weak capacity design	Renewal slippage; output-performance deductions; RNF margin falling well below its five-year band
ERCOT	STP nuclear plus gas/peaking sites, scarcity pricing, flexibility, site/interconnection optionality	Moderate 5-10 year; weakly proven 20 year	New supply, transmission buildout, weather losses, price intervention, rapid storage substitution, larger integrated rivals	Sustained low scarcity/spreads after hedge roll; EFOF deterioration; unfavorable PUCT rules
Other Power Regions	Geographic diversity, selected hydro/renewables, ISO-NE/West capacity and flexibility	Weak-to-moderate 5 year; low-confidence 10-20 year	Mixed asset quality, low margins, carbon rules, commoditization	RNF margin remains near the 7.8%-18.0% quarterly range; asset impairments or forced retirements
Calpine	Efficient gas fleet, 725 MW Geysers geothermal resource, storage, cogeneration, powered land/interconnections, retail channel and risk platform	Moderate 5-10 year; unproven 20 year as owned blend	Spark-spread compression, carbon costs, integration failure, customer loss, storage/renewables displacement	Full-year RNF below deal base; EFOF rises; customer attrition; debt/collateral crowds out maintenance; data-center milestones slip

Mid-Atlantic's moat is the combination of irreplaceable sites and nuclear operating capability, but the segment is not a regulated utility earning a fixed allowed return. Its TTM RNF margin was 51.2%, down from 55.8% in FY2024 and only slightly above FY2021's 49.4%; this is a strong asset base with market exposure, not a toll road. Crane would deepen the moat if Constellation completes the restart and earns the contracted stream, but until then it is an execution option.

Midwest is the strongest current segment. It generated $3.706 billion of TTM RNF, the highest segment total, and five-year RNF margins of 59.4%-69.9%. Braidwood, Byron, Dresden, LaSalle, Quad Cities, and Clinton create exceptional nuclear density, while Meta converts Clinton from expiring policy support to a corporate PPA. Existing-site growth reinforces the barrier: the segment appendix identifies an $800 million Braidwood/Byron uprate program for 158 MW plus 30 MW at Clinton, avoiding much of the siting and interconnection burden of greenfield capacity. The break point is straightforward: operational performance normalizes toward peers while power-market, PTC, or PPA support weakens.

New York exhibits the highest and most stable recent RNF margins: 61.9%-73.7% over FY2021-FY2025 and 73.2% TTM. The cluster has operational scale and valuable carbon-free capacity. In January 2026, the New York PSC adopted ZEC 2.0 through 2049 with formulaic tranches, output-performance conditions, federal-credit coordination, and periodic review ([PSC announcement](https://dps.ny.gov/news/commission-announces-extension-nuclear-power-credit-program)). That is a stronger 2046 floor than a temporary discretionary subsidy, but it is not fixed margin protection. NMP1 and Ginna had current license expirations in 2029 before pending renewals, FitzPatrick's current license expires in 2034, and NMP2's in 2046. Renewal and output performance therefore remain part of the moat, not footnotes.

ERCOT's RNF recovered from negative $825 million in FY2021 to $1.137 billion in FY2025, then held at $1.132 billion TTM. That reversal is evidence of volatility, not a stable moat. STP's nuclear output and Calpine's sites/flexibility have scarcity value, while the Freestone/CyrusOne agreement shows physical chokepoint monetization. Direct rivals are formidable: Vistra

and NRG have larger Texas retail franchises and similarly integrated generation, hedging, credit, and customer platforms. ERCOT added 14.8 GW in 2025—mostly solar and storage—showing how quickly new supply can compete away energy and ancillary rents. ERCOT lacks a centralized capacity market and exposes the portfolio to weather, nodal basis, new build, and intervention.

Other Power Regions is the clearest dilution. RNF margin ranged from 13.7% to 23.0% in FY2021-FY2025, fell to 14.7% in FY2025, and was only 16.2% TTM. Diversity may reduce company-level volatility, but a mixed collection of merchant, renewable, hydro, and retail positions is not itself a moat. The segment appendix also flags an evidence problem: CEG does not disclose the internal geography, technology margin, or share of contracted MW, so investors cannot tell whether low aggregate margin is a stable diversified equilibrium or adverse selection among weak books and assets. This segment should earn little durability credit until margins and returns stabilize.

Calpine contains genuine jewels and commodity businesses in the same segment. The Geysers is the world's largest geothermal complex, capable of about 725 MW around the clock and supported by a unique reservoir and recycled-water infrastructure ([Calpine](https://www.calpine.com/clean-and-reliable-power/our-assets/geothermal/)). Powered-land contracts monetize scarce interconnection and site readiness: Freestone phase 1 is 380 MW with exclusivity for another 380 MW ([official announcement](https://www.constellationenergy.com/news/2026/02/constellation-and-cyrusone-announce-agreement-to-support-new-data-center-facility-at-freestone-energy-center-in-texas.html)). Conversely, standard gas generation and retail supply remain contestable against Vistra, NRG, utilities, independent generators, renewables, storage, and demand response. The segment appendix's exact conclusion—moderate portfolio moat rather than franchise moat—is persuasive: sites, permits, interconnections, fuel access, risk systems, and the Geysers are hard to copy, but a newer turbine or better gas basis can still out-earn a given plant. Only 84 days were consolidated in Q1 FY2026, so the 47.0% RNF margin is not cycle-tested under CEG ownership.

The blended company moat is weaker than Midwest/New York nuclear margins imply. FY2025 Other Power Regions and the newly acquired Calpine/retail/thermal footprint enlarge commodity, carbon, and execution exposure. Nuclear remains the protectable core; diversification improves resilience but lowers the purity of the moat and makes sustained high returns depend on disciplined contracting and capital allocation.

3. Margin persistence evidence

Constellation has only five post-separation annual observations, not a clean ten-year standalone history. Statutory operating margin moved from negative 1.8% in FY2021 to 2.0%, 6.5%, 18.5%, and 12.1% in FY2022-FY2025; TTM statutory operating income was $4.967 billion on $29.867 billion revenue, or 16.6%. This is expansion from a distorted low base with material hedge, collateral, market, and policy effects—not stable ten-year evidence. ROIC similarly rose from negative 1.35% to 16.9% in FY2024 before falling to 12.0% in FY2025, below the Gideon 15% durability threshold.

Segment RNF margin	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Mid-Atlantic	49.4%	41.4%	56.9%	55.8%	52.6%	51.2%
Midwest	66.9%	59.4%	69.9%	66.6%	63.8%	60.4%
New York	73.7%	66.9%	61.9%	70.9%	73.1%	73.2%
ERCOT	(69.9%)	26.4%	43.2%	67.5%	59.7%	60.3%
Other Power Regions	18.2%	13.7%	21.2%	23.0%	14.7%	16.2%
Calpine	N/A	N/A	N/A	N/A	N/A	47.0% partial-period

Midwest and New York provide the clearest persistence. Mid-Atlantic is healthy but more variable. ERCOT's recovery is impressive yet cyclical, while Other Power Regions lacks evidence of attractive durable margins. RNF also sits before O&M, depreciation, and other operating costs; high RNF margins cannot be treated as segment operating margins. The statutory margin and ROIC record therefore support a real operating advantage but do not yet prove a 20-year high-return compounder.

4. AI disruption stress test

AI cannot prompt a licensed reactor, geothermal steam field, turbine, gas pipeline, interconnection, transmission upgrade, or 24/7 delivery obligation into existence. The generation segments are **physical chokepoint economics**. AI may improve outage planning, trading, load forecasting, preventive maintenance, customer service, and dispatch, but those tools will diffuse to competitors and do not erase Constellation's sites, licenses, infrastructure, or operating history.

The most protected segment is Midwest: irreplaceable high-capacity-factor nuclear units plus the Clinton/Meta contract. New York is similarly protected physically but more exposed to license and state-support decisions. Mid-Atlantic gains platform-adjacent upside because AI data centers create demand for scarce reliable clean supply and because Crane is contract-backed; FERC's evolving co-location rules nevertheless determine how much rent asset owners may retain ([FERC fact
sheet](https://ferc.gov/news-events/news/fact-sheet-ferc-directs-nations-largest-grid-operator-create-new-rules-embrace)). Calpine is partly platform-adjacent through powered land, gas flexibility, storage, and the Geysers, yet much of its gas and retail economics remain competitive.

The most AI-exposed activity is customer-facing retail and energy management. A foundation model with access to interval data and market prices can automate quoting, load forecasting, procurement optimization, service, and reporting. That compresses workflow margins and lowers some barriers. The moat must therefore live in credit, licenses, physical hedges, nationwide market access, complex settlement systems, and trusted delivery—not the user interface. AI is a net demand tailwind for generation but a modest commoditization threat to retail workflows.

5. The 2046 test

Today is 2026-08-06; the test date is 2046-08-06. A plausible 2046 business description is: *Constellation owns and operates a national portfolio of nuclear, geothermal, flexible generation, storage, and customer energy contracts. Hyperscalers, industrials, public entities, retail aggregations, and regional grids buy firm electricity, clean-energy attributes, capacity, flexibility, steam, and site/interconnection services. The company still operates Peach Bottom, Dresden, Limerick, Clinton, STP, and other successfully relicensed reactors; Crane and Clinton are completing the final year of their original 20-year Microsoft and Meta contracts or have been recontracted. The Geysers supplies scarce firm renewable output. A smaller gas fleet runs fewer hours but earns reliability, ramping, capacity, or contracted data-center revenue, with the least efficient units retired or converted. Retail remains a distribution channel rather than the primary moat.*

Directionally, 2046 RNF margin could remain near today's blended level, while statutory operating margin could be stable or modestly higher if contracted clean generation grows faster than low-margin retail and if post-acquisition integration costs recede. That is not a forecast of a precise percentage. Several current licenses already reach to 2046 or beyond—Braidwood 2 to 2047, Clinton to 2047, Dresden to 2049/2051, Limerick to 2044/2049, Peach Bottom to 2053/2054, and STP to 2047/2048—while other units require subsequent renewals. The [NRC
process](https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal) can add a second 20-year term but is not automatic. The intact moat would be licensed sites, trained nuclear operations, unique geothermal resource, interconnection scarcity, investment-grade contracting capacity, and high-trust delivery.

The bear 2046 description is materially different: most merchant nuclear plants survive only after repeated subsidies or unfavorable recontracting; several renewals fail or become uneconomic; Crane overruns; data-center demand disappoints or hyperscalers build captive supply; batteries, transmission, and new generation compress scarcity; carbon rules strand much of the gas fleet; retail margins automate and commoditize; and high maintenance, decommissioning, collateral, and debt absorb cash. Constellation remains a large generator but produces mid-cycle commodity returns rather than compounding at high ROIC.

That erosion case is plausible—roughly one-third, not remote—because the federal Section 45U nuclear PTC applies only to electricity sold after 2023 and before 2033 and phases down with facility gross receipts ([IRS
instructions](https://www.irs.gov/instructions/i7213)). Clinton itself previously faced closure after years of losses before ZEC support, and the Meta PPA explicitly replaces that support. Existing 20-year contracts prove demand and counterparty commitment, but not fleet-wide pricing power through 2046. A specific 2046 company can be described; sustained high returns through that date are not yet sufficiently evidenced for PASS.

6. Competitive threat inventory

Threat	Mechanism	Segment(s) affected	Earliest observable signal	Plausibility
Market and policy reallocate scarcity rent	Price caps, capacity redesign, co-location cost allocation, PTC/ZEC expiry, mandated supply, or new-build preference reduce realized RNF	All; especially Mid-Atlantic, Midwest, New York, ERCOT	Adverse FERC/RTO/state orders; lower capacity accreditation; falling RNF despite high availability	High

Threat	Mechanism	Segment(s) affected	Earliest observable signal	Plausibility
Operational/license failure	Long outages, aging capex, fuel constraints, NRC delay, or Crane restart miss removes high-margin output and forces replacement purchases	Nuclear regions	Capacity factor below 92% over a rolling year; rising non-refueling outage days; renewal/restart schedule slippage	Medium
Thermal/retail commoditization and decarbonization	New gas/renewables/storage/transmission compress spreads; carbon costs strand gas; automated procurement compresses retail margins	Calpine, ERCOT, Other Power Regions, unallocated retail	EFOF and customer retention worsen; post-hedge RNF falls; impairments; retail margin per MWh declines	High

7. Pricing power verification

Pricing power is visible in **tenor and complexity**, not disclosed unit price. Microsoft and Meta accepted 20-year arrangements large enough to support restart, life extension, uprate, and ongoing plant investment. CyrusOne contracted 380 MW of Freestone infrastructure and granted exclusivity for another 380 MW. Management reported more than 10,000 MW of the fleet under long-term deals by March 2026. These facts indicate that scarce 24/7 supply, clean attributes, and powered sites can command bankable commitments.

The evidence is incomplete. Contract prices, escalators, minimum-payment structures, churn, retention, renewal rates, and retail margin per MWh are not disclosed. Segment RNF margins held up through inflation in Midwest and New York but compressed in Mid-Atlantic and Other Power Regions, and RNF is not gross margin or operating margin. ERCOT and wholesale revenue remain price takers at the margin. The 10-K explicitly warns that retail barriers can be low and competitors can pursue share aggressively during low-price, low-volatility periods. Therefore, pricing power is **strong for a limited set of nuclear and site-specific contracts, weak for commodity MWh and standard retail, and unverified for the blended portfolio**.

8. Moat verdict

- **Moat gate: YELLOW**
- **2046 test: YELLOW**

Constellation owns one of the strongest physical and operating moats in U.S. competitive power: scarce licensed nuclear sites, a fleet-level operating record, unique geothermal resource, difficult-to-replicate interconnections, and demonstrated ability to sign 20-year hyperscaler contracts. The gate does not reach PASS because statutory margin/ROIC history is volatile and short, a large part of the post-Calpine blend remains exposed to commodity spreads, retail competition, and regulation, and fleet-wide pricing power is not observable. The 2046 company is specific and plausible, with multiple current licenses and the Microsoft/Meta contracts reaching to or beyond the test year, but high-return durability still requires successful relicensing, contract renewal beyond the first hyperscaler cohort, gas-fleet adaptation, and post-PTC economics.

Upgrade both gates to PASS if (1) three full combined-company years show statutory ROIC consistently above 15% after maintenance and integration spending, (2) nuclear capacity factor remains around 94% while multiple subsequent licenses/restarts are granted on time, and (3) disclosed contract coverage expands without RNF or cash-conversion dilution. Downgrade the moat to FAIL if rolling nuclear capacity factor falls below roughly 92% with rising non-refueling outages, or if Midwest/New York RNF margins fall below prior troughs after PTC/ZEC transitions. Downgrade the 2046 test to FAIL if license/restart slippage combines with weak recontracting and Calpine gas/retail returns remain commodity-like after a full cycle.

Appendix B1 - Mid-Atlantic

Mid-Atlantic - Segment Deep Dive

Company: Constellation Energy Corporation (CEG) **Historical anchor:** Q1 FY2026 TTM ended 2026-03-31 **Forecast horizon:** 2031-03-31, exactly five calendar years after the TTM end **Exact profit basis throughout: RNF (Operating revenues net of Purchased power and fuel expenses) Scenario probabilities:** Bear 25%; Base 55%; Bull 20%

This appendix forecasts Mid-Atlantic RNF. It does not forecast segment operating income, because CEG does not disclose statutory operating income by reportable segment. It also does not allocate corporate, unallocated, operating-expense, depreciation, tax, interest, or other statutory-bridge lines into Mid-Atlantic. Those bridge items remain outside this segment model, exactly as required by the sealed statutory bridge [data_package section 3a, Forecast-driver ledger]. All company historical figures, company quotations, and issuer classifications below come only from `data_package.md` and `statutory_bridge.json`. External sources are used only for live market, regulatory, and competitor context and are cited at the point of use.

0. Segment boundary and taxonomy note

Mid-Atlantic is CEG's Eastern PJM generation-and-customer portfolio. Its boundary was stable within the five-geography reporting structure through FY2025. The January 7, 2026 Calpine acquisition created a sixth reportable segment, Calpine, but did not restate Mid-Atlantic or transfer disclosed Mid-Atlantic historical dollars into a new taxonomy [data_package section 1, Reporting structure and taxonomy]. Therefore FY2021-FY2025 Mid-Atlantic comparisons are usable on the disclosed geography basis, while Calpine remains entirely separate. CEG does not disclose an additive product hierarchy inside Mid-Atlantic. The finest valid dollar-disclosed unit is the whole regional generation-and-customer portfolio [data_package section 4, Mid-Atlantic row]. Named plants, PPAs, retail channels, and customer classes are economic drivers, not fabricated financial sub-segments.

1. What this segment actually is

Mid-Atlantic combines two sides of a regional power business. On the supply side, CEG owns or controls generation exposed to Eastern PJM energy, capacity, ancillary-service, environmental-credit, and bilateral-contract economics. On the demand side, its customer-facing platform sells power and related solutions to commercial, industrial, institutional, public-sector, and other retail or wholesale buyers. The segment therefore is neither a pure merchant generator nor a regulated utility. It is a regional portfolio that matches generation, hedges, procured power, and customer load over different time horizons.

The distinction matters because reported revenue is gross of purchased power and fuel, whereas the sealed segment-performance measure is RNF: operating revenue less those two direct commodity inputs. A customer contract can increase revenue while requiring offsetting purchases; a generation outage can leave customer revenue intact but force replacement purchases; a rise in power prices can raise generation value and purchased-power cost simultaneously. Revenue alone consequently gives an incomplete view. RNF is the better disclosed indicator of the portfolio's economic spread before operations and maintenance, depreciation, non-income taxes, and other statutory bridge items.

Pricing occurs through several mechanisms. Merchant generation can realize day-ahead, real-time, capacity, ancillary, and environmental values, but CEG also uses a ratable hedging program and bilateral sales. Customer contracts can include fixed-price, indexed, shaped, renewable, capacity, or load-following components. Long-duration power purchase agreements can convert a portion of uncertain merchant output into contracted cash economics, while the nuclear production tax credit, or PTC, acts as a downside cushion for qualifying nuclear generation but phases down as gross receipts rise. This creates a partial collar rather than a free one-way option on higher power prices [data_package sections 0a and 3].

Go-to-market is portfolio-based. CEG can sell energy from its generation fleet, procure power where customer shape differs from plant output, hedge prompt exposure, and bundle clean-energy attributes or reliability. The commercial advantage is not simply having a plant; it is having generation, market access, risk systems, and a large customer platform capable of structuring multi-year transactions. Management describes long-term deals such as Meta and Microsoft as an ordinary part of strategy, but the data package does not assign every company-level contract to Mid-Atlantic RNF. This appendix includes only regionally relevant, source-bound drivers and never invents contract revenue.

PJM is crucial to the model. It is both an energy market and a forward capacity market, with locational constraints and a central reliability procurement. Eastern PJM includes major load centers and transmission zones in Pennsylvania, New

Jersey, Maryland, Delaware, Virginia, and the District of Columbia. Load growth can support energy volumes and capacity scarcity, but it can also increase congestion, basis risk, transmission cost, and replacement-power exposure. The segment's economic result depends on where generation injects, where customers consume, how those positions are hedged, and whether physical supply is available at the critical hour.

CEG does not provide segment customer counts, retail MWh, generation MWh, capacity MW, or plant-by-plant RNF for Mid-Atlantic. The correct analytical response is to model the disclosed regional portfolio as one financial line and analyze nuclear availability, load, capacity, merchant prices, contracts, and regulation as drivers around it. Splitting revenue into invented nuclear, retail, capacity, or data-center dollar lines would create false precision and fail the sealed taxonomy.

2. Current economics

Mid-Atlantic is the largest disclosed segment by TTM revenue. TTM revenue was **$6.669 billion**, TTM RNF was **$3.414 billion**, and the RNF margin was **51.2%** [data_package section 1, Mid-Atlantic row; section 3, Mid-Atlantic table]. FY2025 revenue was $6.487 billion, up 17.5%, while FY2025 RNF was $3.411 billion and the RNF margin was 52.6% [data_package section 3, Mid-Atlantic Revenue, YoY, RNF, and RNF margin rows]. The TTM revenue rise relative to FY2025 did not translate into higher RNF because the TTM window rolled in Q1 FY2026 and rolled out Q1 FY2025; this illustrates why gross revenue is not the same as economic spread.

The most recent quarter was softer on RNF margin even though revenue grew. Q1 FY2026 Mid-Atlantic revenue was $1.847 billion, up 10.9% from $1.665 billion, while RNF was $0.812 billion and the RNF margin was 44.0% [data_package section 5, Mid-Atlantic Q1'26 row and section 5 spot-check]. The preceding three quarters had RNF margins of 54.0%, 50.6%, and 57.6% [data_package section 5, Mid-Atlantic Q2'25, Q3'25, and Q4'25 rows]. That 13.6-point range is a warning against annualizing one quarter. It also demonstrates the effect of seasonality, hedges, outages, power procurement, and market settlements on a spread-based metric.

Five-year history establishes a wide but positive RNF range. FY2021-FY2025 revenue increased from $4.584 billion to $6.487 billion, a calculated 9.0% CAGR. RNF moved from $2.264 billion to $3.411 billion, a calculated 10.8% CAGR, but the path was uneven: RNF declined to $2.138 billion in FY2022, then recovered to $2.924 billion in FY2023, $3.080 billion in FY2024, and $3.411 billion in FY2025 [data_package section 3, Mid-Atlantic Revenue and RNF rows]. RNF margins ranged from 41.4% to 56.9%, with the latest TTM at 51.2% [data_package section 3, Mid-Atlantic RNF margin row]. The appropriate five-year forecast is thus a scenario distribution, not a straight-line extrapolation of FY2025.

Capital intensity is high even though segment capex is not disclosed. Nuclear plants require refueling, maintenance, security, regulatory programs, long-lived-component work, outage execution, and eventual decommissioning. The wider company is also funding uprates and the Crane restart, but `data_package.md` does not allocate company capex to Mid-Atlantic. Accordingly, this appendix does not subtract a fictional segment capex number from RNF or treat RNF as free cash flow. RNF is upstream of operations and maintenance, depreciation, and taxes other than income taxes under the sealed bridge [data_package section 3a, FY2025 and TTM bridges].

No sub-product share is disclosed in dollars. The segment mixes owned generation, customer sales, purchased power, fuel, hedges, capacity, ancillary services, environmental products, and longer-duration contracts. Fleet-wide nuclear output and capacity-factor data are useful operating context, but not a Mid-Atlantic allocation: company nuclear output was 183 TWh in FY2025 at a 94.7% capacity factor and 44.666 TWh in Q1 FY2026 at 92.3% [data_package section 0a, Historical operating KPI series]. These statistics support the quality of CEG's nuclear operating platform without authorizing a Mid-Atlantic volume split.

3. Unit economics

Revenue-to-RNF conversion

Mid-Atlantic RNF equals operating revenue less purchased power and fuel expense. The numerator includes generation sales, retail and wholesale customer revenue, capacity and ancillary value, and other operating revenue classified to the region. The deductions include replacement or portfolio power purchases and fuel. This measure is economically closer to a gross spread than to statutory operating profit. Labor, maintenance, planned and unplanned outage expense, depreciation, property and payroll taxes, and corporate costs are downstream in the statutory bridge and must not be confused with RNF.

The generation side creates positive convexity to available low-variable-cost output. When a nuclear unit is online, incremental fuel cost per MWh is generally low relative to gas-fired marginal generation, allowing the plant to capture energy and capacity value. When it is offline, the problem is double-sided: foregone generation revenue can be accompanied by

purchased replacement power to serve customer commitments. Because CEG hedges and matches generation against load, the exact effect depends on the hedge book, congestion basis, and contract shape rather than simply multiplying outage MWh by a hub price.

The customer side can stabilize economics but introduces load-shape risk. A fixed-price customer contract creates revenue visibility, yet CEG must supply the customer's actual hourly consumption. Weather, operational schedules, and rapid large-load ramps can change volume and shape. A contract can be attractive if CEG owns matching generation or hedges the shape effectively; it can destroy RNF if procurement cost rises above contracted revenue. Scale in customer analytics, credit, procurement, scheduling, and risk limits is therefore part of the unit economics.

Key RNF drivers

Nuclear availability. Fleet-wide capacity factor stayed between 94.4% and 94.8% in each FY2021-FY2025 year, which is unusually stable for a capital-intensive fleet [data_package section 0a, Historical operating KPI series]. Q1 FY2026 capacity factor fell to 92.3% because planned refueling outage days reached 99, while non-refueling outage days were zero [data_package section 0a, Last-four-quarter nuclear and thermal operations]. Planned outages are not an economic failure if budgeted and executed, but their timing shifts quarterly RNF. Unplanned outage duration, extended inspections, and refueling overruns are more damaging because power may already have been sold.

Energy price and basis. The PJM West day-ahead around-the-clock reference rose from $33.74/MWh in FY2024 to $50.19/MWh in FY2025 after falling from $72.90/MWh in FY2022 [data_package section 0a, Market reference prices, PJM West / Mid-Atlantic row]. These are reference prices, not CEG realized prices. They indicate market regime and volatility but must not be multiplied by CEG output. Hedges, nodal basis, capacity, PTC, customer load, and purchased power mean realized RNF can move differently.

Capacity. The Eastern Mid-Atlantic Area Council reference capacity price moved from $51.89/MW-day in FY2024 to $179.79/MW-day in FY2025 [data_package section 0a, Capacity reference prices, EMAAC row]. The latest PJM 2028/2029 auction subsequently cleared at the FERC-approved RTO cap of $325/MW-day and remained 6,831 MW short of the reliability requirement. PJM said the entire footprint cleared at one price in that auction, with nuclear representing 20% of cleared/committed UCAP [PJM, July 14, 2026 capacity-auction release](https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2026-releases/20260714-pjm-capacity-auction-procures-138318-mw-of-generation-resources.pdf). Capacity is therefore an important upside driver for available firm generation, but auction collars, accreditation, performance risk, and future new supply limit extrapolation.

Nuclear PTC. The PTC reduces downside sensitivity when qualifying nuclear gross receipts are low, but its value phases down as receipts rise [data_package section 0a, Hedges and Market reference prices notes]. It makes RNF less sensitive to modest merchant-price downside in protected years, while muting some upside. A model that adds full merchant-price upside and the maximum PTC simultaneously would double count. The base and bull cases therefore allow higher capacity and contract economics but do not assume an unchanged maximum PTC.

Hedging and contract duration. CEG historically described a three-year ratable sales plan with approximately 90%, 60%, and 30% coverage by promptness; FY2022 year-end coverage for Mid-Atlantic, Midwest, New York, and ERCOT was 94%-97% for 2023 and 75%-78% for 2024 [data_package section 0a, Hedges, contracted load, and PPAs]. These are historical benchmarks, not current segment hedge percentages. They explain why spot-market changes reach RNF with lags. Long-term clean-energy PPAs can extend visibility further, but pricing is confidential.

Load. PJM's January 2026 forecast expected summer peak demand to reach 191,017 MW in 2031 and projected 3.6% average annual summer-peak growth over ten years, versus only 0.3% in the 2021 forecast. It explicitly included data-center adjustments in AEP, ATSI, APS, BGE, JCPL, METED, PECO, PEPCO, PPL, Dominion, and other zones [PJM, 2026 Long-Term Load Forecast summary](https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/). Load growth supports demand for energy and capacity, but PJM also reduced near-term forecasts relative to the prior year after stricter vetting. This is why the base case is below Mid-Atlantic's recent 12.4% FY2023-FY2025 revenue CAGR.

Congestion and transmission. Large loads can be built faster than transmission or new generation. That can raise local capacity and energy value, but it can also widen the basis between a plant node, hub hedges, and customer delivery points. The segment benefits only if it has deliverable generation or well-priced procurement. Transmission upgrades and front-of-meter requirements may also allocate network costs to projects differently from initial commercial assumptions.

Margin mechanics

The TTM RNF margin of 51.2% is the starting point. A 100-basis-point change equals roughly $66.7 million of RNF on current TTM revenue, before any volume change. At the base 2031 revenue forecast of $8.426 billion, 100 basis points equals about $84.3 million. Therefore small errors in generation availability, purchased-power cost, capacity realization, or hedge basis compound into meaningful RNF differences. The model does not translate the $325/MW-day auction clearing price into a segment margin because the data package provides neither Mid-Atlantic accredited capacity nor realized capacity revenue. It likewise does not translate PJM West energy prices into RNF because the data package explicitly says those prices are references rather than CEG realizations.

Margin rises when owned low-variable-cost generation captures stronger realized prices or capacity value, when contracts earn attractive clean/reliability premiums, when load growth is served from matching output, and when outage performance is strong. Margin falls when customer revenue is procurement-heavy, outages force expensive purchases, fuel or basis costs rise faster than revenue, the PTC phases down before contracts reprice, or competitive retail pricing transfers commodity value to customers.

The five-year history cautions against assuming permanent expansion. The 56.9% FY2023 high and 41.4% FY2022 low bracket very different commodity and hedge conditions [data_package section 3, Mid-Atlantic RNF margin row]. The base endpoint is 52.0%, only 80 basis points above TTM. The bull endpoint is 56.5%, just below the disclosed annual high rather than assuming a new record without segment-level MW, hedge, or realized-price disclosure. The bear endpoint is 42.0%, close to the FY2022 annual trough and appropriately below the latest 44.0% weak quarter for a sustained hedge/basis/procurement failure.

4. Competitive dynamics

Competitor set

Mid-Atlantic competes with other PJM generators and customer suppliers rather than a single like-for-like company. Nuclear competitors include Talen's Susquehanna plant and PSEG/Vistra nuclear interests; gas, coal, hydro, storage, demand response, and imports compete in energy and capacity markets. Retail and commercial competition includes integrated generators, utilities' competitive affiliates, independent suppliers, and sophisticated customers procuring directly. The data package does not disclose a reliable CEG Mid-Atlantic market share, and no market-share percentage is inserted here.

Talen's Amazon arrangement is the clearest competitive analogue for pairing existing PJM nuclear output with data-center load. EIA described a 960 MW Susquehanna capacity arrangement and explained that nuclear's large unit size, low operating cost, continuous output, and lack of direct carbon emissions fit steady data-center demand [EIA, October 1, 2024](https://www.eia.gov/TODAYINENERGY/detail.php?id=63304). This validates demand for CEG's clean firm output, but it also proves that CEG is not the only nuclear owner able to contract with hyperscalers.

Regulatory design is part of competition. FERC rejected a non-conforming PJM interconnection agreement for the Susquehanna co-location structure, and later proceedings reflected a move toward a front-of-meter arrangement [FERC docket ER24-2172](https://www.ferc.gov/media/er24-2172-pjms-susquehanna-co-location-proposal). The lesson is not that data-center PPAs are invalid; it is that network cost allocation, backup supply, transmission use, and interconnection configuration can determine economics. CEG's advantage depends on structuring contracts that survive regulatory review, not merely announcing MW.

PJM's overall supply mix is diversified. The 2028/2029 capacity auction reported 46% natural gas, 20% nuclear, 18% coal, and smaller contributions from demand response, hydro, wind, oil, and solar on a UCAP basis [PJM capacity-auction release](https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2026-releases/20260714-pjm-capacity-auction-procures-138318-mw-of-generation-resources.pdf). Nuclear is scarce and dependable, but gas is the largest competitor and can set energy prices. New gas, uprates, storage, demand flexibility, transmission, or delayed load could reduce scarcity before 2031.

Pricing power

CEG has no unilateral pricing power in PJM's organized spot markets. Energy and capacity prices are set by market rules, bids, system conditions, and mitigation. The July 2026 capacity auction applied offer limits under the Three-Pivotal Supplier Test and cleared at a regulatory price cap [PJM capacity-auction release]. That is attractive near-term market evidence but also proof that policy constrains price realization.

Pricing power is stronger in differentiated bilateral products. A buyer seeking 24/7 carbon-free power, multi-year certainty, large scale, creditworthy execution, and a credible delivery path has fewer choices than a buyer of undifferentiated annual renewable energy certificates. Existing nuclear interconnections and high availability cannot be recreated quickly. Yet contract

prices are confidential, customers can run competitive processes, Talen and other owners can offer alternatives, and new-build gas plus clean attributes can compete economically.

The load-serving platform adds negotiating leverage because CEG can shape and firm supply rather than simply deliver a plant's flat output. This capability matters for hyperscale demand, which is steady but not perfectly flat and may ramp in phases. It also creates risk: CEG can win a large customer by underpricing load shape or basis. Revenue growth is not evidence of pricing power unless RNF grows at least proportionately.

Supply-demand balance

PJM's 2028/2029 capacity auction procured 138,318 MW UCAP, and total auction plus fixed-resource-requirement UCAP was still 6,831 MW below the reliability requirement. PJM said demand was growing faster than supply and noted only 525 MW UCAP of new generation and uprates cleared [PJM capacity-auction release]. This supports a scarcity thesis through the late 2020s, especially for accredited existing generation.

However, scarcity is not guaranteed through 2031. PJM accepted more than 700 projects into its reformed interconnection process in August 2026, and it is pursuing accelerated interconnection, backstop procurement, flexible load, and market reform. Load forecasts are also uncertain. The January 2026 outlook reduced 2027-2031 peaks relative to the 2025 report even as long-run growth remained high [PJM 2026 forecast summary]. Base therefore assumes healthy but decelerating segment revenue, not permanent double-digit growth or endless capacity-cap pricing.

Substitution risk

The main substitutes are: gas generation with firm fuel; coal life extensions; storage combined with renewables; demand response and flexible data-center load; imports; and behind-the-meter generation. EIA modeled Mid-Atlantic prices as less sensitive than ERCOT to high demand because PJM is interconnected and has access to coal and gas capacity [EIA, April 2026 high-demand scenario](https://www.eia.gov/todayinenergy/detail.php/detail.php?id=67344). This limits the assumption that every incremental data-center MWh becomes nuclear supernormal profit.

Nuclear remains differentiated on round-the-clock carbon-free output, but customers may accept emissions-backed supply with renewable certificates, shift workloads, build gas behind the meter, or defer projects. Storage duration and economics could improve over five years. The competitive question is not whether nuclear is useful; it is how much premium survives after alternatives and grid costs are priced.

5. Moat at the segment level

Mid-Atlantic has a real but conditional moat. The strongest component is the existing nuclear fleet and interconnection position. Operating nuclear plants at high capacity factors requires specialized personnel, regulatory systems, security, maintenance discipline, fuel management, outage planning, and a long record of safe operation. New nuclear supply is slow and expensive, while an existing interconnection in a constrained region has option value. PJM's latest auction accredited nuclear at a meaningful share of dependable capacity, and official market evidence shows growing scarcity.

The second moat is portfolio integration. CEG can combine physical generation with customer load, hedges, capacity, ancillary services, environmental products, and long-term contracts. A standalone plant can sell commodity output, and a standalone retailer can procure power, but the integrated platform can tailor risk across both sides. Scale matters because hourly load and basis require data, credit, collateral, scheduling, and risk governance.

The third moat is clean-firm scarcity. Data centers need high-load-factor supply, and many large buyers have carbon goals. EIA notes that nuclear units generally provide large blocks of continuous, low-direct-emission power well matched to steady data-center demand [EIA nuclear/data-center analysis](https://www.eia.gov/TODAYINENERGY/detail.php?id=63304). Existing nuclear output is difficult to substitute with a single renewable asset because wind and solar are variable; firming them adds procurement and infrastructure.

The moat is not absolute. PJM market prices are regulated and competitive. Customers can solicit Talen, Vistra, PSEG, utilities, gas generators, renewables-plus-storage developers, or new entrants. CEG's plants are capital intensive and exposed to rare but severe outage and regulatory events. Nuclear PTC protection is public policy rather than proprietary advantage, and it phases down with receipts. Transmission cost or co-location rules can transfer economics from generator to grid or customer.

Crane illustrates both moat and fragility. The data package identifies a 20-year Microsoft PPA for approximately 835 MW, targeted for the second half of 2027 subject to approvals [data_package section 0a, Hedges, contracted load, and PPAs,

Microsoft / Crane row]. The NRC's live project page shows a formal restart panel, a site-specific inspection plan, continuing licensing actions, and regulatory review; it also shows that restart requires approval and restored components, not just commercial intent [NRC Crane project page](https://www.nrc.gov/info-finder/reactors/ccec). An already-interconnected retired reactor is a scarce option, but execution, licensing, refurbishment, and timing risk are substantial.

Over five to ten years, the moat should protect participation and bargaining relevance more reliably than a fixed margin. In base, high availability, scarce capacity, and selective contracts keep RNF margin modestly above TTM. In bull, successful restart/contract execution, capacity scarcity, and strong basis management produce a premium margin. In bear, the assets remain valuable but procurement, outages, regulation, or delayed load compress RNF. The correct conclusion is **durable strategic position, cyclical and execution-sensitive spread**.

6. Historical growth rates

The table reproduces the finest dollar-disclosed economic unit. CEG discloses no additive products inside Mid-Atlantic, so the segment itself is the single valid line. The three observations FY2023-FY2025 imply a two-year CAGR of 12.4%; the table labels the interval explicitly rather than calling two compounding periods three years. Most recent annual YoY is 17.5%. No dollars are back-solved.

Product / sub-segment	FY2023 revenue	FY2024 revenue	FY2025 revenue	FY2023-FY2025 CAGR	Most recent annual YoY	Data package cite
Regional generation and customer portfolio [data_package section 4, Mid-Atlantic product/economic-unit row]	$5.138B [data_package section 3, Mid-Atlantic Revenue row]	$5.522B [data_package section 3, Mid-Atlantic Revenue row]	$6.487B [data_package section 3, Mid-Atlantic Revenue row]	12.4% calculated from [data_package section 3, Mid-Atlantic Revenue row]	17.5% [data_package section 3, Mid-Atlantic YoY row]	[data_package section 4, Mid-Atlantic product/economic-unit row]

Arithmetic tie-outs: FY2023 $5.138B x 1.075 = $5.523B versus disclosed $5.522B, a 0.02% rounding difference. FY2024 $5.522B x 1.175 = $6.488B versus disclosed $6.487B, a 0.02% rounding difference. Both are comfortably inside the required 2% tolerance. The calculated FY2021-FY2025 revenue CAGR is 9.0%, using $4.584B and $6.487B from the same data-package revenue row. The FY2023-FY2025 acceleration should not be extrapolated unchanged because capacity and energy prices normalized upward, load forecasts remain uncertain, and TTM RNF did not grow with TTM revenue.

For profit context, RNF was $2.924B in FY2023, $3.080B in FY2024, and $3.411B in FY2025, while RNF margins were 56.9%, 55.8%, and 52.6% [data_package section 3, Mid-Atlantic RNF and RNF margin rows]. The 8.0% FY2023-FY2025 RNF CAGR lagged revenue's 12.4% CAGR because the RNF margin contracted 430 basis points. That is the key warning embedded in the history: gross growth can coexist with weaker spread conversion.

7. Management guidance and contract anchors

The data package contains no Mid-Atlantic-specific FY2026 revenue or RNF guide. The following company-level statements are relevant to the regional model, but none is treated as a disclosed Mid-Atlantic dollar allocation.

- **Contract strategy - Q2 FY2025, CEO Joe Dominguez.** Data-package row: section 6, Contract strategy. Verbatim: **"long-term contracts like our Meta and Microsoft deals"** are becoming **"an ordinary part of our strategy"**. Interpretation: the base case can assume continued contracting of selected output, but it cannot insert an undisclosed contract price or assign all company contracts to Mid-Atlantic.

- **Contracted fleet - Q4 FY2025, CEO Joe Dominguez.** Data-package row: section 6, Contracted fleet. Verbatim: **"executed deals for over 10,000 megawatts of our fleet"**. Interpretation: company-wide contracted MW support visibility and show buyer demand for firm power. [DATA GAP: The data package does not allocate the over-10,000-MW contracted fleet to Mid-Atlantic, disclose contract revenue, or provide the segment's current hedge percentage.]

- **Growth capex - Q4 FY2025, CFO Shane Smith.** Data-package row: section 6, Growth capex. Verbatim: **"$3.9 billion in growth projects"** with **"returns of at least 10% on an unlevered basis"**. Interpretation: projects can add output and RNF, but this is company-wide capital and a return target, not Mid-Atlantic guidance. The segment model gives only scenario credit for source-bound regional execution.

- **Customer scale - Q1 FY2026, CFO Shane Smith.** Data-package row: section 6, Customer scale. Verbatim: **"approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually"**. Interpretation: the

combined customer platform provides cross-sell and risk-management scale, but the data package does not provide Mid-Atlantic customer volumes.

Two non-quote data-package anchors matter. The Microsoft / Crane agreement is a 20-year PPA for approximately 835 MW of restart output, targeted for the second half of 2027 subject to approvals [data_package section 0a, Microsoft / Crane row]. The legacy merchant program was a three-year ratable sales plan, historically approximately 90% / 60% / 30% [data_package section 0a, Legacy merchant hedge plan row]. These anchors support a blend of contracted and merchant economics. They do not justify counting 835 MW as current TTM output or treating historical hedge percentages as present coverage.

[DATA GAP: No segment-specific revenue guide, RNF guide, capacity MW, generation MWh, customer load, current hedge percentage, realized price, contract price, or product-dollar split is disclosed for Mid-Atlantic.]

8. Forward growth assumptions

The TTM starting revenue is $6.669 billion [data_package section 3, Mid-Atlantic Revenue row]. Because no additive product dollars exist, each scenario models the one disclosed regional portfolio. Forecast growth is driven by the interaction of load, price, capacity, contracts, availability, and gross purchased-power/customer revenue. CAGR means 2026-03-31 to 2031-03-31 exactly.

Base case growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Base CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	12.4% [data_package section 3, Revenue row]	17.5% [data_package section 3, YoY row]	No segment-specific guide [data_package section 6]	4.8%	PJM load and capacity remain supportive, but recent growth decelerates as capacity prices, hedges, and customer mix normalize; contracts improve visibility without invented pricing.

The base path is 7.0%, 6.0%, 5.0%, 3.5%, and 2.5% annual growth. It produces revenue of $7.136B, $7.564B, $7.942B, $8.220B, and $8.426B. The CAGR is 4.787%. This deliberately decelerates from 17.5% latest annual growth and 10.9% Q1 FY2026 growth. The structural support is PJM's 3.6% ten-year summer-peak growth forecast and data-center adjustments across numerous Eastern PJM zones [PJM 2026 forecast summary]. The terminal CAGR is 1.19 percentage points above that non-comparable peak-demand reference; that residual is the explicit allowance for price/capacity/customer mix, not an implied MWh forecast. The fade reflects forecast vetting, potential new supply, hedge roll, and PTC offset.

The year-by-year deceleration is not sharper than the market evidence warrants. Near-term auction scarcity and announced contracts support above-terminal growth in 2026-2028. By 2029-2031, new generation, transmission, demand flexibility, and competitive procurement should absorb some scarcity. Crane is treated as a risk-weighted contributor to the regional portfolio, not a separate dollar line. The base does not require every announced data center to connect or the capacity auction to clear at its cap forever.

Bull case growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Bull CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	12.4% [data_package section 3, Revenue row]	17.5% [data_package section 3, YoY row]	No segment-specific guide [data_package section 6]	7.6%	Load arrives near PJM's stronger zonal expectations, scarce accredited nuclear capacity retains premium value, Crane executes, and customer contracts add volumes without major procurement leakage.

The bull path is 10.0%, 9.0%, 7.5%, 6.0%, and 5.5%, producing revenue of $7.336B, $7.996B, $8.596B, $9.112B, and $9.613B. The CAGR is 7.586%. This remains below the segment's 12.4% FY2023-FY2025 CAGR and below the latest 17.5% annual growth. Economically it is demanding: the terminal CAGR is about 4.0 percentage points above PJM's ten-year peak-demand forecast and therefore requires sustained price/capacity/customer-mix uplift as well as load. It is a 20%-probability upside, not a run-rate extrapolation.

PJM's 2028/2029 auction clearing at the $325/MW-day cap with a 6,831 MW reliability shortfall is the central structural support. Crane licensing and restart progress adds output around the late-2020s horizon, while existing plants capture capacity and clean-firm demand. The bull also assumes CEG manages customer load shape and congestion well enough that revenue converts into RNF. It does not add the maximum PTC to full price upside.

Bear case growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Bear CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	12.4% [data_package section 3, Revenue row]	17.5% [data_package section 3, YoY row]	No segment-specific guide [data_package section 6]	0.5%	Data-center timing slips, load forecasts are derated, new supply and transmission reduce scarcity, and customer growth is procurement-heavy; PTC cushions price downside but not gross-revenue stagnation.

The bear path is 2.0%, 1.0%, 0.0%, negative 0.5%, and 0.2%, producing revenue of $6.802B, $6.870B, $6.870B, $6.836B, and $6.850B. The CAGR is 0.536%. The endpoint sits about 3.1 percentage points below PJM's ten-year peak-demand reference, consistent with delayed loads, lower realized prices, and customer/procurement gross-up failing to add value. This is not an arbitrary collapse: PJM itself reduced near-term load forecasts after stricter large-load vetting, and EIA notes that interconnection with other regions plus available coal and gas can limit Mid-Atlantic wholesale-price response [EIA high-demand analysis].

Bear assumes delayed or downsized large loads, capacity-price normalization after the collar period, competitive retail pricing, and weaker generation/customer matching. It does not assume plant closure or loss of all demand. The segment's existing position and PTC floor keep revenue broadly stable, while RNF margin captures most of the downside.

9. Forward segment-profit margin assumptions - RNF (Operating revenues net of Purchased power and fuel expenses)

Exact profit metric: RNF (Operating revenues net of Purchased power and fuel expenses). The TTM starting margin is 51.2%. Product-level margins cannot be disclosed or calculated because there are no additive product revenues inside the segment. The regional portfolio is therefore the only valid margin line.

Case	Exact profit metric	TTM margin	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31 margin	Change vs TTM	Specific mechanism
Bear	RNF (Operating revenues net of Purchased power and fuel expenses)	51.2%	49.0%	47.0%	45.0%	43.0%	42.0%	(920) bps	Procurement-heavy load, outages or basis losses, contract competition, capacity normalization, and delayed data-center demand push the full-year endpoint close to the FY2022 trough.
Base	RNF (Operating revenues net of Purchased power and fuel expenses)	51.2%	51.5%	51.5%	51.8%	52.0%	52.0%	+80 bps	High availability and constructive capacity/contract mix offset PTC phase-down and procurement cost, but absent disclosed segment MW or realized prices the model does not capitalize the auction headline into a larger margin step-up.

Case	Exact profit metric	TTM margin	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31 margin	Change vs TTM	Specific mechanism
Bull	RNF (Operating revenues net of Purchased power and fuel expenses)	51.2%	52.0%	53.5%	55.0%	56.0%	56.5%	+530 bps	Scarcity capacity, strong clean-firm contracts, successful restart/output growth, excellent availability, and favorable basis return the segment near—but not above—its disclosed annual margin high.

The bear endpoint of 42.0% is 920 basis points below TTM and only 60 basis points above FY2022's 41.4% annual margin. The mechanism is a sustained adverse spread rather than one weak quarter: customer revenue is maintained partly through expensive purchased power; market prices or congestion diverge from hedge positions; capacity prices normalize; and contract competition prevents passing costs through. The PTC and hedge book cushion qualifying downside, but neither protects plant availability, nodal basis, load shape, or every purchased-power dollar. The endpoint uses the disclosed annual trough, rather than a single quarter, as the relevant severity anchor.

The base endpoint is 52.0%, close to FY2025's 52.6% and only 80 basis points above TTM. Higher capacity value, selective clean-firm contracting, and operating availability prevent deterioration, while PTC phase-down at higher receipts, competitive contract pricing, hedge lags, and procurement-heavy customer growth prevent a large margin expansion. With no disclosed Mid-Atlantic accredited MW, realized capacity revenue, hedge coverage, or contract pricing, this is a modest spread-normalization case rather than an assumption that auction prices flow one-for-one to RNF.

The bull endpoint of 56.5% sits 40 basis points below the disclosed FY2023 high. It still requires successful conversion of new or restored output into premium contracts, sustained PJM capacity scarcity, strong plant availability, and favorable generation-to-load basis. It does not assume that the maximum nuclear PTC remains additive when gross receipts rise, and it does not treat the $325/MW-day auction cap as a permanent realized segment price. Because the conditions must occur together, the bull probability remains 20%. The model does not include corporate synergies, O&M savings, depreciation, or tax effects in this margin.

An important asymmetry is that revenue and RNF margin may move in opposite directions. A high-price, high-load market can raise revenue but force expensive replacement purchases; a hedged low-price environment can suppress revenue while preserving spread. The rollup therefore calculates RNF from scenario revenue multiplied by scenario RNF margin. It does not apply a price beta to TTM RNF.

10. Segment rollup

The rollup uses one dollar-disclosed product line. Product sum therefore equals segment revenue exactly. The blended margin is the same line's RNF margin. All figures are USD billions except percentages, and rounding can create a $1 million display difference.

Case	Product / economic unit	Exact profit metric	TTM revenue	Five-year CAGR	2031-03-31 revenue	2031-03-31 profit margin	2031-03-31 profit	Revenue tie-out
Bear	Regional generation and customer portfolio	RNF (Operating revenues net of Purchased power and fuel expenses)	$6.669B	0.536%	$6.850B	42.0%	$2.877B	100.0%
Base	Regional generation and customer portfolio	RNF (Operating revenues net of Purchased power and fuel expenses)	$6.669B	4.787%	$8.426B	52.0%	$4.381B	100.0%
Bull	Regional generation and customer portfolio	RNF (Operating revenues net of Purchased power and fuel expenses)	$6.669B	7.586%	$9.613B	56.5%	$5.431B	100.0%

Arithmetic: Bear $6.849724B x 42.0% = $2.876884B, displayed as $2.877B. Base $8.425659B x 52.0% = $4.381343B, displayed as $4.381B. Bull $9.612729B x 56.5% = $5.431192B, displayed as $5.431B. Each total reconstructs directly from sections 8 and 9 and ties within 0.1%. The base implies five-year RNF growth from $3.414B to $4.381B, a 5.12% CAGR. Bull RNF grows at 9.73% annually; bear RNF declines at 3.37% annually despite slightly positive revenue growth, demonstrating margin downside.

The year-by-year RNF schedule below makes the margin weighting explicit. Revenue is compounded from the unrounded $6.669B TTM base by the annual growth rates in section 8; RNF equals each unrounded revenue value multiplied by that year's RNF margin in section 9.

Case	Metric	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31
Bear	Revenue ($B)	6.802	6.870	6.870	6.836	6.850
Bear	RNF margin	49.0%	47.0%	45.0%	43.0%	42.0%
Bear	RNF ($B)	3.333	3.229	3.092	2.940	2.877
Base	Revenue ($B)	7.136	7.564	7.942	8.220	8.426
Base	RNF margin	51.5%	51.5%	51.8%	52.0%	52.0%
Base	RNF ($B)	3.675	3.895	4.114	4.274	4.381
Bull	Revenue ($B)	7.336	7.996	8.596	9.112	9.613
Bull	RNF margin	52.0%	53.5%	55.0%	56.0%	56.5%
Bull	RNF ($B)	3.815	4.278	4.728	5.102	5.431

The probability-weighted 2031 segment outcome is $8.269B revenue and $4.215B RNF, calculated from 25% bear, 55% base, and 20% bull using unrounded terminal values. The ratio of probability-weighted RNF to probability-weighted revenue is 50.98%, but that is a diagnostic rather than a fourth scenario. This is the correct margin-weighted result: scenario RNF is weighted directly, rather than multiplying probability-weighted revenue by an average of the three margins. The main synthesis should consume the three scenario values independently and apply the same scenario structure across other segments and bridge lines.

Scenario interpretation

Bear is not a recession-only case. It is a combination of slower load realization, lower scarcity value, adverse procurement or basis, and weaker RNF conversion. The existing portfolio survives, but gross revenue fails to compound and margin resets close to the latest weak quarter. A Crane delay is a contributor, not the only cause.

Base assumes the PJM scarcity and load thesis is real but shared with competitors and constrained by policy. Recent double-digit revenue growth fades toward mature growth. Existing and new contracts improve visibility, capacity stays constructive, and nuclear performance remains strong. Margin expands modestly rather than returning instantly to the bull-like peak.

Bull assumes load arrives quickly, reliable supply remains scarce, contracts monetize clean firm value, and new/restored output performs. It also requires skilled basis and customer-shape management. Because regulatory price caps, competitor projects, and PTC phase-down all limit upside, bull is not assigned the highest probability.

11. Key risks and wildcards

1. Nuclear outage and restart execution - Bear

Nuclear plants concentrate output in large units. A prolonged unplanned outage can simultaneously remove generation, trigger replacement purchases, and impair capacity performance. Planned refueling schedules also create quarterly noise. Crane adds refurbishment, fuel, licensing, inspection, staffing, and schedule risk. The NRC's restart panel and inspection plan show real process, but not final authorization [NRC Crane project page]. Bear captures delayed output and lower margin; base requires no major fleet-wide outage; bull requires strong availability plus timely project execution.

2. Large-load forecast error - Bear and Bull

Data-center service requests can be duplicated, speculative, phased, delayed, or smaller than nameplate. PJM's 2026 process derated less-firm projects and lowered near-term peaks relative to the prior forecast [PJM 2026 forecast summary]. Conversely, Virginia commercial electricity sales rose sharply and PJM projects significant zonal load growth [EIA, May 5, 2026](https://www.eia.gov/TODAYINENERGY/detail.php?id=67664). Bull needs actual energized load and payment, not

announcements. Bear assumes material slippage.

3. Capacity-market redesign and price collars - Bear

The 2028/2029 auction cleared at a regulatory cap, and PJM is pursuing backstop procurement, accelerated interconnection, flexible-load arrangements, and broader market reform. These actions can improve reliability while limiting incumbent scarcity rents. Capacity is valuable, but a capped auction price is not a perpetual terminal price. Base assumes constructive capacity economics without extrapolating the cap to 2031.

4. Co-location, network-cost, and interconnection rules - Bear and Base

FERC and PJM treatment can determine whether a large load is behind or in front of the meter, which party funds transmission, how backup supply is charged, and whether existing capacity remains available to the grid. Talen's Susquehanna structure demonstrates that contracts can be revised to fit rules [FERC docket ER24-2172]. CEG can still contract, but project returns may change. No undisclosed co-location saving appears in this model.

5. PTC phase-down - Base and Bull

The nuclear PTC supports low-receipt periods but declines as gross receipts rise. It reduces downside yet can make high market-price upside less than a simple merchant sensitivity. Bull therefore depends on capacity, contract premium, output, and basis as well as price. Double counting full PTC and full merchant upside would overstate RNF.

6. Merchant hedge roll - Bear and Bull

Historical ratable hedging delays spot-market transmission into earnings. Strong market prices may not fully reach RNF until hedges roll; weak prices may be cushioned for a period. Current segment coverage is not disclosed [DATA GAP]. The five-year endpoint spans several hedge vintages, increasing eventual market sensitivity but reducing confidence in annual timing.

7. Customer load shape and credit - Bear

Large customers need around-the-clock power but can ramp over years, change utilization, or negotiate flexibility. Retail contracts may include fixed prices or shape obligations. If actual hourly load differs from hedges and generation, CEG procures power at unfavorable prices. Credit concentration could also rise as individual hyperscalers become large. The data package does not disclose segment customer concentration.

8. Congestion and basis - Bear and Bull

PJM is not one price. Generation node, load zone, hub hedge, and capacity locational value can diverge. Transmission constraints can create premium local value when positioned well or losses when customer and generation locations mismatch. Bull assumes disciplined basis monetization; bear assumes congestion and network charges consume part of gross market upside.

9. Competitive new supply and life extensions - Bear

PJM's high prices encourage gas projects, uprates, storage, demand response, imports, and delayed retirements. The NRC lists numerous expected uprate applications across 2026-2031, including multiple proprietary CEG projects and competitor projects, but plant allocation is not yet public [NRC expected uprate applications](https://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/expected-applications). New accredited supply can reduce capacity scarcity. The model gives no Mid-Atlantic dollars for unidentified projects.

10. Fuel, maintenance, and inflation - Bear

RNF deducts fuel but not O&M. Fuel-price or purchased-power inflation can directly compress RNF, while maintenance inflation affects statutory profit later in the bridge. This appendix captures only the former in RNF margin. The synthesis must separately forecast O&M, depreciation, and taxes without allocating them back to this segment.

11. Environmental and political policy - All cases

Nuclear PTC, state support, environmental regulation, market-price mitigation, and consumer affordability interventions can change the distribution of value. Policy can support zero-carbon reliability yet cap capacity prices or reallocate network costs. Bull assumes policy preserves investable returns; bear assumes affordability and market redesign limit capture.

12. Disclosure risk - All cases

The absence of segment MW, output, load, hedge, realized price, customer concentration, and contract price prevents a full price-volume bridge. This is a real underwriting limitation, not a reason to manufacture precision. Monitoring should focus on reported regional revenue, RNF, RNF margin, quarterly outage metrics, capacity results, load forecast revisions, and disclosed contract milestones.

Monitoring dashboard through 2031

The base case should be revisited if any of these occur: two consecutive Mid-Atlantic quarters below 45% RNF margin without planned-outage explanation; material Crane licensing or schedule slippage; PJM load forecasts for 2030-2031 fall by more than 10% versus the January 2026 baseline; capacity auctions clear materially below the collar after supply additions; or regional revenue grows while RNF declines for a full year. Positive revisions require equally hard evidence: energized large load, disclosed contract economics, successful restart milestones, incremental accredited MW, and sustained RNF conversion rather than announcements alone.

Quarterly revenue should be interpreted alongside RNF. A revenue beat accompanied by weak RNF can reflect purchased-power gross-up rather than improved economics. Capacity-factor and outage-day data are fleet-wide context, not automatic explanations for Mid-Atlantic. Analysts should ask management for regional generation volume, customer load, hedge coverage, capacity MW, and realized price, but until disclosed those remain data gaps.

The five-year thesis is ultimately a spread-underwriting problem. PJM load and scarcity make Mid-Atlantic strategically attractive, and nuclear plus customer integration creates real option value. Yet competition, regulation, grid costs, PTC phase-down, and physical execution determine how much value appears in RNF. The probability distribution therefore centers on measured growth and modest margin expansion, with a meaningful bear case despite strong market headlines.

Summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	$6.850B	RNF (Operating revenues net of Purchased power and fuel expenses)	42.0%	$2.877B	25%
Base	$8.426B	RNF (Operating revenues net of Purchased power and fuel expenses)	52.0%	$4.381B	55%
Bull	$9.613B	RNF (Operating revenues net of Purchased power and fuel expenses)	56.5%	$5.431B	20%

Bottom line: Mid-Atlantic is a high-quality but volatile Eastern PJM spread portfolio. Its moat comes from existing nuclear assets, interconnections, operating capability, customer scale, and the ability to structure clean-firm contracts. Its TTM economics are strong at $6.669B revenue and $3.414B RNF, but the 44.0%-57.6% last-four-quarter RNF margin range shows that availability, procurement, and market structure matter. Base compounds revenue at 4.787% to $8.426B and expands RNF margin only to 52.0%, producing $4.381B of 2031 RNF. That is a credible central case only if PJM load growth becomes real demand, capacity remains constructive, nuclear performance stays strong, and contracting does not sacrifice spread; the restrained endpoint does not assume that auction scarcity creates a large margin step-up without segment-level realization evidence.

Data gaps retained

- [DATA GAP: The data package does not allocate the over-10,000-MW contracted fleet to Mid-Atlantic, disclose contract revenue, or provide the segment's current hedge percentage.]
- [DATA GAP: No segment-specific revenue guide, RNF guide, capacity MW, generation MWh, customer load, current hedge percentage, realized price, contract price, or product-dollar split is disclosed for Mid-Atlantic.]
- [DATA GAP: The data package does not disclose Mid-Atlantic customer concentration, plant-level RNF, or a bridge from PJM reference prices to CEG realized regional prices.]

External source record

External market and regulatory sources were retrieved live on 2026-08-06 and are not sources for CEG historical financials, management quotations, or issuer classifications:

- [PJM 2026 Long-Term Load Forecast summary](https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/)
- [PJM 2028/2029 capacity-auction release, July 14, 2026](https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2026-releases/20260714-pjm-capacity-auction-procures-138318-mw-of-generation-resources.pdf)
- [EIA on Virginia/PJM data-center load, May 5, 2026](https://www.eia.gov/TODAYINENERGY/detail.php?id=67664)
- [EIA on Mid-Atlantic nuclear and data-center contracting](https://www.eia.gov/TODAYINENERGY/detail.php?id=63304)
- [EIA high-electricity-demand scenario for PJM](https://www.eia.gov/todayinenergy/detail.php/detail.php?id=67344)
- [NRC Crane Clean Energy Center project page](https://www.nrc.gov/info-finder/reactors/ccec)
- [NRC expected power-uprate applications](https://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/expected-applications)
- [FERC docket ER24-2172, PJM Susquehanna co-location proposal](https://www.ferc.gov/media/er24-2172-pjms-susquehanna-co-location-proposal)

Appendix B2 - Midwest

Midwest — Segment Deep Dive

Company: Constellation Energy Corporation (CEG) **Run:** `pulse-cio-20260806T090230+0800` **Historical and forecast anchor:** TTM ended 2026-03-31 **Forecast horizon:** 2031-03-31, exactly five calendar years **Reporting currency:** USD billions unless stated otherwise **Exact segment profit basis: RNF (Operating revenues net of Purchased power and fuel expenses)**

RNF is the issuer-disclosed segment performance measure. It is revenue after purchased power and fuel, but before operating and maintenance expense, depreciation and amortization, taxes other than income taxes, and the other corporate and statutory bridge lines. It is therefore not statutory operating income, and this appendix never calls it operating income. Historical CEG figures, management quotations, taxonomy, and accounting classifications come only from the verified `data_package.md` and `statutory_bridge.json`. External links are used only for current fleet, market, regulatory, and competitive context.

0. Segment boundary and taxonomy note

The Midwest boundary is stable for comparable legacy history: it comprises CEG's operations in the western half of PJM and the U.S. footprint of MISO excluding MISO South. CEG reported the same Midwest regional portfolio throughout FY2021-FY2025, and the January 2026 Calpine acquisition did not move Calpine assets into Midwest; Calpine became a separate reportable segment. Consequently, the FY2021-FY2025 Midwest revenue and RNF series is comparable without a recent restatement. The only naming evolution is that the 2022 filing used "Revenue Net of Purchased Power and Fuel Expense," whereas the sealed current label is **RNF (Operating revenues net of Purchased power and fuel expenses)**; the concept is unchanged, but the sealed current label controls [data_package §1, taxonomy paragraph].

The finest dollar-disclosed unit is the Midwest regional generation and customer portfolio itself. CEG does not publish additive Midwest revenue or RNF by nuclear station, energy, capacity, environmental credit, hedge, retail load, or customer class [data_package §4, introductory paragraph and Midwest row]. Those drivers are modeled explicitly, but they are not presented as fabricated product revenue lines.

1. What this segment actually is

Midwest is a regional merchant-generation and customer-supply portfolio whose economic core is CEG's Illinois nuclear fleet, complemented by a much smaller set of wind and storage interests and a commercial/customer book. The current fleet context includes Braidwood, Byron, Clinton, Dresden, LaSalle, and Quad Cities. These are large, low-variable-cost, baseload nuclear facilities; the region also contains smaller wind interests and a battery asset. CEG's official fleet disclosure places six Illinois nuclear stations in the Midwest asset inventory and describes the geographic segment as western PJM plus non-South MISO. This structural fleet context is not used to replace the verified financial history [CEG current fleet exhibit filed with the SEC](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000045/ceg-202603318kexh991.htm).

The customer proposition is not simply "sell nuclear megawatt-hours at spot." CEG combines owned generation with wholesale and retail load obligations, bilateral sales, capacity commitments, environmental attributes, ancillary services, and financial/physical hedges. It can sell power through exchange-settled markets, to utilities and competitive retail suppliers, and under multi-year or very long-term contracts to large commercial customers. Purchased power fills customer obligations when owned output, location, or timing does not match load. Fuel expense is principally nuclear fuel for the Midwest generation fleet. The segment's RNF therefore captures the spread between operating revenues and purchased power plus fuel, while leaving fleet O&M and depreciation to the later statutory bridge.

Pricing comes through several linked mechanisms:

- Energy sales reflect hub and nodal power prices, congestion and basis, plant availability, hedge settlements, and the shape of the customer load book.
- PJM capacity value is set through Reliability Pricing Model auctions and bilateral/FRR arrangements. MISO uses seasonal resource-adequacy accreditation and a Planning Resource Auction.
- Illinois carbon-support mechanisms pay for environmental attributes at specified plants, but their design offsets energy, capacity, PTC, or other market receipts rather than granting unlimited additive upside.

- The federal section 45U zero-emission nuclear production tax credit is a downside support mechanism whose value falls as qualifying gross receipts rise.
- Long-term contracts exchange some merchant optionality for visibility. Clinton's 20-year Meta agreement begins in June 2027, supports 1,121 MW, includes a planned 30 MW uprate, and succeeds the expiring state ZEC support at that plant [data_package §0a, Hedges/contracts row; data_package §9, 2025-06-03 action].

The go-to-market model matters because a nuclear plant is physically inflexible but commercially versatile. High-capacity-factor output can be layered into retail and wholesale commitments, hedged years ahead, sold into day-ahead and real-time markets, or contracted with customers that value 24/7 carbon-free supply. The plant supplies a relatively steady physical volume; the commercial organization determines how much price, basis, load-shape, credit, and duration risk the company retains. This is why segment revenue can be volatile even when nuclear output is stable, and why RNF is more decision-useful than revenue alone.

The segment is unusually exposed to the interaction between policy floors and market upside. Braidwood, Byron, and Dresden participate in Illinois Carbon Mitigation Credit support through May 2027; Clinton and Quad Cities have ZEC support through May 2027, while LaSalle is supported by the federal PTC framework rather than those state programs in CEG's current program schedule. The state mechanisms are designed around environmental attributes and market offsets, while 45U remains available for qualifying production through 2032 and phases down with gross receipts. Thus, low power prices can be cushioned, but strong energy and capacity prices are not simply added on top of a full credit. The model treats support as a floor and stabilization tool rather than a free second revenue stream.

2. Current economics

Midwest generated **$6.132 billion of TTM revenue**, **$3.706 billion of RNF (Operating revenues net of Purchased power and fuel expenses)**, and a **60.4% RNF margin** in the twelve months ended 2026-03-31 [data_package §3, Midwest table, TTM column; QFR-sealed `TTM_NORMALIZED_RECONCILIATION`]. It is the largest reportable CEG segment by TTM RNF [data_package §5, concluding paragraph]. FY2025 revenue was $5.804 billion, up 20.8%, while FY2025 RNF was $3.702 billion and the RNF margin was 63.8% [data_package §3, Midwest table, FY2025 column; [2025 Form 10-K, Note 5 and MD&A pp. 67-68](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)]. The most recent quarter showed $1.732 billion revenue, 23.4% year-over-year growth, $0.854 billion RNF, and a 49.3% RNF margin [data_package §5, Midwest Q1'26 row; [Q1 FY2026 Form 10-Q, Note 5 p. 20 and MD&A pp. 59-61](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm)].

That quarterly combination—rapid revenue growth and a much lower RNF margin—is a useful warning against equating revenue growth with economic growth. The direct comparison is unusually stark: Q1 FY2026 Midwest revenue rose $328 million, but purchased power and fuel rose $324 million, leaving RNF up only $4 million, from $850 million to $854 million, or 0.5% [Q1 FY2026 Form 10-Q, Note 5 p. 20 and MD&A pp. 59-61]. Purchased-power and fuel pass-throughs, customer mix, outage timing, hedge realization, and high-price periods can expand gross revenue without proportionate RNF. Conversely, a lower-revenue period can produce attractive RNF if generation availability, hedge settlements, capacity, credits, and load matching are favorable. The segment should therefore be forecast with a revenue path and an independent RNF margin path, not a fixed margin carried mechanically from a strong year.

The five-year record illustrates the same point. Revenue rose from $4.060 billion in FY2021 to $5.804 billion in FY2025, but RNF margins ranged from 59.4% to 69.9%. FY2023 achieved the high point of 69.9% on $4.658 billion revenue; FY2025 revenue was 24.6% higher than FY2023, yet its 63.8% RNF margin was 610 basis points lower [data_package §3, Midwest table; [2022 Form 10-K, segment table](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm); [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)]. This does not indicate a broken business. It shows that gross revenue contains power procurement and pass-through effects that do not necessarily accrue to segment profit.

The segment is capital intensive in an economic sense: nuclear units require scheduled refueling outages, life-extension work, security, regulatory compliance, cooling systems, fuel inventory, maintenance, and periodic uprates. Those cash needs do not appear inside RNF. Constellated operating expenses, D&A, taxes other than income tax, corporate activity, and financing are handled downstream in the sealed statutory bridge. **[DATA GAP: CEG does not disclose Midwest segment capex, maintenance capex, invested capital, or statutory operating income.]** It would therefore be improper to calculate a Midwest ROIC or to allocate consolidated capex and D&A to Midwest by analyst judgment.

There is also no decision-safe product share table. The Midwest regional portfolio is the sole dollar-disclosed unit; CEG does not split revenue or RNF among the six nuclear stations, wind/storage assets, capacity, power, environmental credits, hedges, retail customers, or long-term contracts [data_package §4]. The asset inventory makes clear that nuclear is structurally dominant, but the appendix does not invent a nuclear percentage of revenue or RNF.

3. Unit economics

The basic unit is a megawatt-hour of dependable generation matched against a megawatt-hour of sold or served load, with separate resource-adequacy and environmental attributes. The segment's physical fleet produces electricity; its commercial book determines where, when, and under what risk-sharing structure that electricity is monetized. Revenue becomes RNF through five main bridges.

First, **owned nuclear output** has high fixed costs but low incremental fuel cost. Once a station is staffed, licensed, maintained, and fueled, an extra available megawatt-hour generally contributes strongly before O&M and D&A. This creates powerful positive operating leverage at the RNF level when capacity factors are high. It also creates negative leverage when an unplanned outage forces CEG to buy replacement power at unfavorable prices while still bearing much of the plant's fixed cost below RNF.

Second, **purchased power and load matching** can expand or compress the spread. CEG's customer business sells shaped products—not a perfectly flat nuclear block. Customers use more power at particular hours and locations. If the generation fleet's output and hedges match those obligations, RNF is protected. If weather, congestion, customer shape, or an outage produces a short position, purchased power can become expensive. This is why the revenue denominator and RNF margin can move in opposite directions.

Third, **capacity and reliability value** reward availability, but the payment is market- and accreditation-specific. PJM's capacity market has tightened: the 2027/2028 auction cleared at the FERC-approved cap of $333.44/MW-day, and PJM reported a 6,623 MW shortfall to its reliability requirement. Almost all of the year-on-year load-forecast increase was linked to data-center demand [PJM 2027/2028 auction release](https://insidelines.pjm.com/pjm-auction-procures-134479-mw-of-generation-resources/). The subsequent 2028/2029 auction also cleared at its $325/MW-day cap, reinforcing the scarcity signal, although the model does not extrapolate a capped auction price indefinitely [PJM 2028/2029 official auction report page](https://www.pjm.com/markets-and-operations/rpm.aspx). MISO's 2026/2027 PRA was also tight in summer: Zones 1-7 cleared at $424.30/MW-day for summer but only $33.92, $35.97, and $7.61 in fall, winter, and spring, yielding $126.19/MW-day annualized for North/Central [MISO 2026 PRA release](https://extranet.misoenergy.org/meet-miso/media-center/2026---news-releases/misos-planning-resource-auction-shows-sufficient-capacity-for-coming-year/). These results support near-term capacity value but also show why annualization and seasonal accreditation matter.

Fourth, **policy support is countercyclical rather than purely additive**. Section 45U applies to qualified nuclear power produced and sold in tax years after 2023 and before 2033. Its base credit is 0.3 cents/kWh and can be multiplied up to five times when prevailing-wage requirements are met, but the amount is reduced based on qualifying gross receipts [IRS section 45U overview](https://www.irs.gov/credits-deductions/zero-emission-nuclear-power-production-credit). CEG's 2025 Form 10-K makes the offset concrete: the transferable credit was up to $15/MWh; 2025 PTC revenue fell to $320 million from $2.080 billion as receipts rose; state-sponsored programs subject to refund or pass-through produced negative $125 million of net revenue; and the average Illinois CMC price was negative $7.58/MWh versus positive $8.05/MWh in 2024 [2025 Form 10-K, MD&A pp. 66-68]. The same filing says state ZEC/CMC provisions can require refunding compensation up to the PTC received or passing through the entire PTC. At the 2031-03-31 horizon, 45U still exists under current law, but it is a downside floor whose incremental value diminishes in high-receipt cases, not an additive source of margin expansion.

Fifth, **hedging changes timing rather than long-run economics**. CEG historically used a three-year ratable merchant sales plan, approximately 90%/60%/30%, and disclosed 94%-97% coverage for 2023 and 75%-78% for 2024 at the end of FY2022 [data_package §0a, Hedges row]. The exact current Midwest hedge percentages are not disclosed. A hedge book dampens prompt-price shocks, but it also delays participation in a rising market. By the outer years of a five-year forecast, more of the portfolio generally rolls toward prevailing price and contract conditions unless new long-duration deals replace merchant exposure.

RNF does **not** include all costs needed to sustain these economics. O&M was $6.394 billion consolidated on the TTM bridge, D&A was $1.180 billion, and taxes other than income tax were $0.691 billion; these are consolidated bridge lines that synthesis must forecast independently, not amounts to allocate to Midwest [data_package §3a, TTM bridge; QFR-sealed `TTM_NORMALIZED_RECONCILIATION`, SHA-256

227bdac4e38cca9b15f36fef332cef5fb35d00faab35013a0f6d4841dc02a0be]. The Midwest segment can post a 60% RNF margin while its statutory operating margin is materially lower. This distinction is central to valuation discipline.

What moves RNF margin

RNF margin expands when owned output and customer load are well matched, plants avoid unplanned outages, capacity and ancillary value strengthen, nuclear fuel remains predictable, higher-value contracts replace expiring support, and procurement costs do not rise as fast as sales. It also benefits when revenue mix shifts toward owned baseload and environmental attributes rather than low-spread purchased-power resale.

RNF margin contracts when outages require replacement purchases, gross revenue grows through low-spread pass-through sales, congestion/basis moves against the commercial book, fuel or purchased-power costs rise, customer load exceeds hedged supply, policy support expires without replacement, or high receipts phase down PTC value faster than market margin rises. A severe nuclear event could also create extended lost output, inspection costs, and reputational consequences that are not captured by a routine margin sensitivity.

4. Competitive dynamics

Midwest does not compete in a conventional branded-product market. It competes every hour against other generators, storage, demand response, imports, customer self-supply, and alternative retail/wholesale marketers. In energy markets, the marginal competitor often sets price. In capacity markets, accredited supply and demand response compete to satisfy resource-adequacy requirements. In long-term contracting, customers compare CEG's nuclear reliability and emissions profile with renewable-plus-storage, gas generation, utility tariffs, and other clean-energy structures.

The most important competitive advantage is **scarce existing firm capacity**. PJM's 2027/2028 auction fell below its reliability requirement even at the price cap, with a 5,250 MW increase in forecast peak load and about 5,100 MW attributable to data centers. Nuclear represented 21% of cleared supply [PJM auction release](https://insidelines.pjm.com/pjm-auction-procures-134479-mw-of-generation-resources/). The 2028/2029 auction again clearing at the cap suggests that incremental supply is not catching projected demand quickly enough. In MISO, current summer capacity is much more valuable than shoulder-season capacity, and the auction cleared only 3.5% above the summer planning reserve margin target [MISO 2026 PRA release](https://extranet.misoenergy.org/meet-miso/media-center/2026---news-releases/misos-planning-resource-auction-shows-sufficient-capacity-for-coming-year/).

The direct merchant-generation peer set includes independent power producers with gas, nuclear, coal, battery, and retail portfolios, as well as utility-owned generation and contracted resources. Yet the competitive benchmark is less "which peer has the same product" than "what new resource can provide comparable accredited, around-the-clock output at the same node and on the same timeline?" Gas can be dispatchable but faces fuel, pipeline, emissions, and permitting constraints. Renewables can be low-cost energy but require overbuild, transmission, storage, and accreditation adjustments to replicate firm nuclear output. Storage is valuable for hours, not multi-day energy. Demand response can reduce peaks but depends on customer performance and revised accreditation rules. Existing nuclear therefore has a strong scarcity position, although it does not have unconstrained price-setting power because auctions, contracts, PTC, CMC/ZEC offsets, market monitors, and political interventions shape monetization.

Load growth improves the demand side of the equation but is not guaranteed. PJM's 2026 load forecast projects ComEd summer peak growth of 3.9% annually over ten years and 2.6% over fifteen years; its winter peak growth forecasts are higher at 5.6% and 3.8%, respectively [PJM 2026 Load Forecast Report](https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf). MISO's 2026 member survey indicates five-year load-growth outcomes of 3.1%-5.1%, while its system planning work also emphasizes wide uncertainty around data-center timing and on-site generation [MISO OMS survey](https://extranet.misoenergy.org/meet-miso/media-center/2026---news-releases/omsmiso-survey-shows-surge-in-new-resource-additions/). These are demand forecasts, not contracted Midwest revenue.

MISO's own planning materials highlight the execution mismatch: large loads may seek connection in 1.5-3 years while new generation takes about four years and major transmission 7-10 years [MISO large-load discussion](https://www.misoenergy.org/meet-miso/media-center/miso-matters/preparing-the-grid-for-large-load-growth/). That favors existing plants, but it can also cause interconnection rationing, delayed customer projects, political cost allocation fights, or behind-the-meter generation that reduces realized grid demand.

Pricing power is therefore **conditional**. CEG has negotiating leverage because an operating nuclear fleet can deliver large-scale, carbon-free, high-load-factor power now. The 20-year Clinton/Meta agreement shows that a customer will

contract around an existing plant to secure long-duration supply and continued operation [Constellation-Meta announcement](https://www.constellationenergy.com/news/2025/constellation-meta-sign-20-year-deal-for-clean-reliable-nuclear-energy-in-illinois.html). But contract prices are confidential, state credits can claw back excess market value, the PTC phases down, and regulators can redesign capacity markets. CEG can improve the durability and duration of its revenue mix; it cannot simply dictate an unrestricted monopoly price.

[DATA GAP: Neither the data package nor verified market sources provide a decision-safe Midwest revenue or RNF market share.] Capacity ownership is not equivalent to revenue share because customer load, hedges, purchased power, partial ownership, accreditation, and contracts alter economics. The report therefore uses fleet scarcity and auction clearing evidence as competitive context rather than inventing a market-share percentage.

5. Moat at the segment level

The Midwest segment has a real but regulated and capital-intensive moat. It rests on five reinforcing assets.

First, replacement difficulty. Six operating nuclear stations embody decades of siting, licensing, construction, grid interconnection, workforce development, and community relationships. A competitor cannot replicate that fleet within a normal five-year investment horizon. New nuclear may eventually add supply, but financing, permitting, construction, and supply-chain lead times make it an implausible direct substitute by 2031 at the same scale.

Second, reliability and scale. Nuclear units can supply large, steady output through weather conditions that impair some alternatives. CEG's fleet-wide data package shows a 94.4%-94.8% annual nuclear capacity-factor range in FY2021-FY2025 and 183 TWh of owned nuclear output in FY2025 [data_package §0a, Historical operating KPI series]. Those are fleet-wide figures, not a fabricated Midwest plant series, but they demonstrate the operating system that supports the segment. The moat depends on maintaining that performance; it is not automatic.

Third, commercial integration. The combination of generation, hedging, wholesale/retail load, capacity-market participation, environmental attributes, and long-term contracts makes the portfolio more valuable than isolated plants sold purely at spot. Management says long-term contracts like Meta and Microsoft are becoming an ordinary part of strategy and that more than 10,000 MW of the broader fleet is under executed deals [data_package §6, Contract strategy and Contracted fleet rows]. Midwest benefits from that platform even though contract-level segment revenue is not disclosed.

Fourth, regulatory embeddedness. State CMC/ZEC programs and federal 45U support recognize the reliability and carbon value of existing nuclear. They can protect the downside when energy economics weaken. However, regulation is a two-edged moat: mechanisms can cap upside, expire, be litigated, or be redesigned. Clinton's Meta PPA is valuable precisely because it replaces the expiring ZEC support from June 2027 rather than assuming the state program continues indefinitely.

Fifth, incremental growth at existing sites. CEG is investing to uprate Braidwood and Byron and plans a Clinton uprate under the Meta agreement. Existing-site uprates generally avoid much of the siting and interconnection challenge of greenfield generation. CEG's current official materials describe an $800 million Braidwood/Byron program and 158 MW of additional capacity, with Clinton adding 30 MW [Constellation innovation page](https://www.constellationenergy.com/work/innovation.html); [Constellation-Meta announcement](https://www.constellationenergy.com/news/2025/constellation-meta-sign-20-year-deal-for-clean-reliable-nuclear-energy-in-illinois.html). The model treats delivery as staged execution, not guaranteed full upside on day one.

The moat should last through the five-year horizon if CEG preserves safety, availability, licenses, and community/regulatory acceptance. Over 10 years, it remains credible but more conditional. Transmission expansion, new gas, storage, demand response, renewables plus long-duration storage, market redesign, customer on-site generation, or major new nuclear could erode scarcity rents. A serious safety or reliability failure could also convert the moat into a liability. Thus the moat is strong in physical scarcity and commercial integration, moderate in unrestricted pricing power, and vulnerable to regulation and operational tail risk.

6. Historical growth rates reproduced from the data package

CEG does not disclose additive products below the Midwest geography. The sole dollar-disclosed line is therefore the regional generation and customer portfolio. The "3-year CAGR" below uses the two annual intervals from FY2023 to FY2025, consistent with the three disclosed observations. A longer FY2021-FY2025 cross-check is shown beneath the table.

Product / sub-segment	FY-3 rev	FY-2 rev	FY-1 rev	3-yr CAGR	Most recent YoY	Data package cite
Midwest regional generation and customer portfolio [data_package §4, Midwest row]	$4.658B [data_package §3, Midwest Revenue row, FY2023]	$4.805B [data_package §3, Midwest Revenue row, FY2024]	$5.804B [data_package §3, Midwest Revenue row, FY2025]	11.6% [calculated from data_package §3, Midwest Revenue row, FY2023-FY2025]	20.8% [data_package §3, Midwest YoY row, FY2025]	2025 Form 10-K Note 5 and MD&A pp. 67-68; data_package §§3-4

Arithmetic checks:

- FY2023 to FY2024: $4.658B × 1.032 = $4.807B versus disclosed $4.805B; difference is 0.04%, within the 2% tolerance.
- FY2024 to FY2025: $4.805B × 1.208 = $5.804B versus disclosed $5.804B; difference is less than 0.01%.
- FY2021 to FY2025: ($5.804B / $4.060B)^(1/4) - 1 = **9.3%**, a useful longer base rate [data_package §3, Midwest Revenue row; 2022 and 2025 Forms 10-K, segment tables].
- Q1 FY2026 revenue of $1.732B grew 23.4% year over year, but RNF margin fell to 49.3%; this supports revenue growth but warns against extrapolating FY2025's 63.8% RNF margin [data_package §5, Midwest Q1'26 row; Q1 FY2026 Form 10-Q, Note 5 p. 20].

No historical dollars are back-solved, and there is no fabricated plant-level series.

7. Management guidance quoted from the data package

CEG has not provided a Midwest revenue or RNF guide. The following data-package statements are the relevant portfolio-level anchors; they constrain the Midwest assumptions but do not become segment guidance by allocation.

- **Contract strategy — 2025-08-07 Q2 FY2025 call; Joe Dominguez, CEO; data_package §6.** "long-term contracts like our Meta and Microsoft deals" are becoming "an ordinary part of our strategy." This supports a gradual shift toward longer-duration, customer-backed economics, particularly as Illinois support programs expire. It does not disclose the Midwest contract price or annual revenue.

- **Contracted fleet — 2026-03-31 Q4 FY2025 call; Joe Dominguez, CEO; data_package §6.** CEG has "executed deals for over 10,000 megawatts of our fleet." The statement indicates material corporate contract coverage, but the data package does not allocate those megawatts or economics to Midwest. The base case therefore gives credit only to the specifically disclosed Clinton/Meta transition and a general stabilization effect, not an invented contracted share.

- **Growth capex — 2026-03-31 Q4 FY2025 call; Shane Smith, CFO; data_package §6.** Management identified "$3.9 billion in growth projects" with "returns of at least 10% on an unlevered basis." Some nuclear uprates are relevant to Midwest, but the quote is corporate and the data package does not split project dollars or returns by segment. The model recognizes announced Midwest uprates physically while leaving capex and statutory return analysis to synthesis.

- **Customer scale — 2026-05-11 Q1 FY2026 call; Shane Smith, CFO; data_package §6.** The combined customer platform serves "approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually." This scale can improve customer matching and cross-sell, but it is not Midwest volume guidance.

- **Corporate FY2026 earnings guide — data_package §6, concluding paragraph.** Management affirmed adjusted operating EPS of $11.00-$12.00 on May 11. This is a corporate, adjusted metric and is not RNF or a statutory bridge line. It is only a later reasonableness check.

[DATA GAP: Management has not disclosed Midwest-specific revenue growth, RNF, RNF margin, current hedge percentage, realized price, load volume, or FY2026 guidance.] The forward model therefore relies on verified history, disclosed contract/capacity/PTC structures, and external market evidence rather than presenting corporate guidance as a segment promise.

8. Forward growth assumptions

The forecast begins with **$6.132 billion of Midwest TTM revenue** at 2026-03-31 and ends on 2031-03-31, exactly five years later. Because the Midwest portfolio is the only dollar-disclosed unit, each scenario has one product line. Operational drivers

are shown separately and do not pretend to be additive revenue products.

Base-case revenue growth

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Base CAGR TTM→TTM+5y	Justification
Midwest regional generation and customer portfolio	11.6% [data_package §3]	20.8% FY2025; 23.4% Q1'26 [data_package §§3 and 5; 2025 10-K pp. 67-68; Q1'26 10-Q pp. 59-61]	No Midwest guide [data_package §6]	4.4%	Tracks the middle of official regional load ranges after allowing for already-realized price/capacity gains, PTC/CMC offsets, low-spread load and 2027 support transitions.

The base case uses annual revenue growth of **6%, 5%, 4%, 4%, and 3%**, producing a 4.4% CAGR and **$7.603 billion** of horizon revenue. This is deliberately below the 11.6% FY2023-FY2025 CAGR and near the 3.9% ten-year ComEd summer-peak forecast and MISO's 3.1%-5.1% five-year survey range. The model gives near-term credit to already-cleared PJM capacity scarcity, MISO summer tightness, load growth and Clinton/Meta, but does not capitalize those drivers twice. In FY2025, Midwest's $2.295 billion of favorable generation/load, hedge, retail, capacity and ZEC revenue drivers were offset by $1.300 billion of lower PTC and CMC revenue; in Q1 FY2026, $328 million of revenue growth generated only $4 million of incremental RNF [2025 Form 10-K MD&A pp. 67-68; Q1 FY2026 Form 10-Q Note 5 p. 20 and MD&A pp. 59-61]. Those facts require a normalization haircut to gross revenue growth and a separate RNF path.

Bull-case revenue growth

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bull CAGR TTM→TTM+5y	Justification
Midwest regional generation and customer portfolio	11.6% [data_package §3]	20.8% FY2025; 23.4% Q1'26 [data_package §§3 and 5; 2025 10-K pp. 67-68; Q1'26 10-Q pp. 59-61]	No Midwest guide [data_package §6]	8.0%	Faster load conversion, sustained capacity scarcity, on-time uprates and additional premium contracts overcome—but do not eliminate—PTC/CMC offsets and pass-through dilution.

The bull case uses **10%, 9%, 8%, 7%, and 6%** annual growth, an 8.0% CAGR, ending at **$9.006 billion**. It assumes PJM and MISO load projects convert closer to system forecasts; capacity remains scarce beyond already-cleared years; Braidwood, Byron, and Clinton uprates arrive on schedule; the customer platform wins additional large-load contracts; and reliability stays high. The 20-year Meta agreement supports the 1,121 MW Clinton output and a 30 MW uprate from June 2027, but it essentially replaces Clinton's expiring ZEC rather than adding a second full payment stream, and its price is undisclosed [Constellation-Meta announcement](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-meta-sign-20-year-deal-clean-reliable-nuclear). The bull therefore stays below the historical 11.6% three-observation CAGR and does not stack full PTC, state support and market upside.

Bear-case revenue growth

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bear CAGR TTM→TTM+5y	Justification
Midwest regional generation and customer portfolio	11.6% [data_package §3]	20.8% FY2025; 23.4% Q1'26 [data_package §§3 and 5; 2025 10-K pp. 67-68; Q1'26 10-Q pp. 59-61]	No Midwest guide [data_package §6]	(1.0%)	Data-center attrition, lower market receipts, unfavorable support transitions and outage/load-matching pressure exceed nominal load and Clinton-contract growth.

The bear case uses **(3%), (2%), (1%), 0%, and 1%** annual growth, a (1.0%) CAGR, ending at **$5.828 billion**. It assumes a significant share of projected large load is delayed, cancelled, served behind the meter, or constrained by transmission; capacity prices normalize after the cleared auctions; CMC/ZEC transitions are unfavorable outside Clinton; and lower energy prices reduce gross receipts. The PTC and Meta agreement prevent a severe structural collapse, but 45U protects only qualifying production and receipts, not outage replacement purchases, basis, shape, low-spread load or every contract-reset risk. A bear case that still grew revenue from the TTM base did not adequately reflect those mechanisms.

Year-by-year thesis-consistency path

Case	Year 1 growth / revenue	Year 2 growth / revenue	Year 3 growth / revenue	Year 4 growth / revenue	Year 5 growth / revenue	Implied CAGR
Bear	(3%) / $5.948B	(2%) / $5.829B	(1%) / $5.771B	0% / $5.771B	1% / $5.828B	(1.0%)

Case	Year 1 growth / revenue	Year 2 growth / revenue	Year 3 growth / revenue	Year 4 growth / revenue	Year 5 growth / revenue	Implied CAGR
Base	6% / $6.500B	5% / $6.825B	4% / $7.098B	4% / $7.382B	3% / $7.603B	4.4%
Bull	10% / $6.745B	9% / $7.352B	8% / $7.940B	7% / $8.496B	6% / $9.006B	8.0%

The base deceleration from 20.8% to 3% is driven by a specific normalization path rather than generic maturation. FY2025 and Q1 FY2026 benefited from strong market and revenue effects, but the same periods demonstrated material PTC/CMC and purchased-power offsets. The horizon includes the roll-off of Illinois support, hedge renewal, potential capacity-price normalization and the likelihood that load forecasts exceed actual interconnections. Bull remains materially below the three-observation CAGR because even that case cannot add capped capacity, full PTC, full CMC/ZEC and premium contracts independently. Bear permits a modest revenue contraction because lower market receipts reduce the denominator even while PTC and Clinton/Meta support continued operation.

Operational driver matrix

Driver	Bear	Base	Bull	Evidence boundary
Nuclear reliability	Extended/unplanned outages and costly replacement power	Fleet performance near verified historical range with normal refueling	Top-tier availability and efficient outages	Fleet capacity factor 94.4%-94.8% FY2021-FY2025 [data_package §0a]
PJM capacity	Prices normalize after cleared years; rule intervention	Cleared scarcity supports near term; no extrapolation beyond observable delivery years	Persistent reserve shortfalls and high capacity value, still subject to the auction collar and redesign	[PJM 2028/29 BRA report](https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf); 2027/28 release
MISO capacity	Summer scarcity eases; shoulder values stay low	Seasonal RBDC value, not summer-price annualization	Load converts faster and North/Central stays tight across more seasons	[MISO 2026/27 PRA results](https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260428754715.pdf): $424.30 summer / $126.19 annualized North/Central
Federal PTC	Valuable floor but cannot offset outages/basis	Downside stabilization; phases down with gross receipts	Little incremental value because qualifying receipts are high	[IRS 45U](https://www.irs.gov/credits-deductions/zero-emission-nuclear-power-production-credit); 2025 10-K pp. 66-68; Q1'26 10-Q Note 6
Illinois support transition	CMC/ZEC expiry creates holes outside Clinton	Clinton PPA replaces its ZEC; other plants are not assumed recontracted	Additional disclosed contracts replace some expiring support, without double counting	[2025 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm) pp. 24, 66-68; [Meta release](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-meta-sign-20-year-deal-clean-reliable-nuclear)
Hedges	Adverse roll and imperfect load shape	Ratable renewal dampens prompt volatility	Rising market captured as hedges roll plus premium contracts	data_package §0a hedge rows
Load growth	Projects delayed, cancelled or behind meter	ComEd/MISO growth converts with execution haircuts	High forecast conversion and 24/7 clean demand	PJM and MISO official load forecasts
Uprates	Delays and cost overruns	Announced Braidwood/Byron/Clinton projects stage in	Full, on-time output plus further low-risk optimization	Official CEG project announcements; no invented revenue split

9. Forward RNF margin assumptions

Exact metric: RNF (Operating revenues net of Purchased power and fuel expenses)

The TTM RNF margin is **60.4%**, calculated from $3.706 billion of RNF divided by $6.132 billion of revenue [data_package §3, Midwest table; QFR-sealed `TTM_NORMALIZED_RECONCILIATION`]. Forecast margin changes are kept separate from statutory costs. No corporate RNF, O&M, D&A, taxes, interest, or other bridge item is allocated into Midwest.

Case	TTM revenue	Exact profit metric	Current margin	TTM+5y revenue	TTM+5y margin	Change	TTM+5y profit	RNF CAGR	Mechanism
Bear	$6.132B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.4%	$5.828B	50.0%	(1,040) bps	$2.914B	(4.7%)	Outages, replacement purchases, adverse load shape, weak support transition and lower receipts/mix
Base	$6.132B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.4%	$7.603B	58.0%	(240) bps	$4.410B	3.5%	Reliability, Clinton/Meta and capacity scarcity support RNF, but pass-through load and PTC/CMC offsets prevent margin expansion
Bull	$6.132B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.4%	$9.006B	63.0%	+260 bps	$5.674B	8.9%	High availability, premium contracts and uprates lift mix, constrained by lower PTC value and customer-supply dilution

Base margin mechanism. The revised 58.0% terminal margin is 240 basis points below TTM and above the 49.3% Q1 FY2026 trough. It does not treat FY2023's 69.9% or FY2025's 63.8% as a steady-state entitlement. Q1 FY2026 showed why: Midwest revenue rose $328 million while purchased power and fuel rose $324 million, so RNF increased just $4 million. FY2025 also showed $1.300 billion of PTC/CMC offsets against favorable market and portfolio revenue drivers [2025 Form 10-K MD&A pp. 67-68; Q1 FY2026 Form 10-Q pp. 59-61]. Reliability, Clinton/Meta and capacity scarcity support recovery from the quarterly trough, but retail/wholesale pass-through growth, support expiry and procurement keep terminal margin below TTM.

Bull margin mechanism. A 63.0% horizon margin is 260 basis points above TTM but slightly below FY2025 and well below the FY2023 high. It requires a cleaner mix of owned generation and contracted value, high plant availability, timely uprates and disciplined customer matching. It also recognizes that strong energy/capacity receipts phase down 45U value, that CMC can become a payment back to ComEd, and that the Meta PPA replaces Clinton's ZEC rather than stacking on top of it. A 66.0% terminal margin did not provide enough room for those offsets while also assuming 8%-10% revenue growth.

Bear margin mechanism. A 50.0% margin is 1,040 basis points below TTM and approximately the Q1 FY2026 trough. The mechanism is not simply lower price. It combines an adverse mix of low-spread customer revenue, replacement-power purchases during outages, unfavorable basis or shape, weaker post-2027 support economics outside Clinton and procurement pressure. The federal PTC and Clinton PPA limit downside, which is why terminal RNF remains $2.914 billion rather than collapsing with gross receipts; they do not justify keeping the margin meaningfully above a recently observed 49.3% quarter in the downside case.

The terminal margins are judgments on the disclosed portfolio, not allocated plant margins. The year-by-year path makes the support transition and mix logic explicit:

Case	Year 1 RNF margin	Year 2 RNF margin	Year 3 RNF margin	Year 4 RNF margin	Year 5 RNF margin	Terminal rationale
Bear	57.0%	54.0%	52.0%	50.0%	50.0%	Support roll-off, outages and low-spread load outweigh the PTC floor
Base	59.0%	58.0%	57.0%	58.0%	58.0%	2027 transition initially dilutes margin; contracts and reliability partly restore it
Bull	61.0%	62.0%	63.0%	63.0%	63.0%	Premium mix and uprates help, but PTC/CMC offsets cap the terminal spread

RNF margin is modeled at the single disclosed portfolio level. Plant-level margins cannot be revenue-weighted because plant revenue and RNF are not disclosed. Creating such lines would add false precision.

10. Segment rollup

The rollup is a one-line sum because Midwest regional generation and customer activity is the only dollar-disclosed product. Revenue is compounded from the sealed TTM anchor using the year-by-year paths in section 8. RNF is horizon revenue multiplied by the case-specific RNF margin in section 9. The single product line therefore reconciles exactly to the segment total.

Case	Product / sub-segment	TTM revenue	TTM+5y revenue	Exact profit metric	TTM+5y margin	TTM+5y profit	Segment tie
Bear	Midwest regional generation and customer portfolio	$6.132B	$5.828B	RNF (Operating revenues net of Purchased power and fuel expenses)	50.0%	$2.914B	100.0%
Base	Midwest regional generation and customer portfolio	$6.132B	$7.603B	RNF (Operating revenues net of Purchased power and fuel expenses)	58.0%	$4.410B	100.0%
Bull	Midwest regional generation and customer portfolio	$6.132B	$9.006B	RNF (Operating revenues net of Purchased power and fuel expenses)	63.0%	$5.674B	100.0%

Arithmetic tie-outs:

- Bear revenue: $6.132B × 0.97 × 0.98 × 0.99 × 1.00 × 1.01 = $5.828B. Bear RNF: $5.828B × 50.0% = $2.914B.
- Base revenue: $6.132B × 1.06 × 1.05 × 1.04 × 1.04 × 1.03 = $7.603B. Base RNF: $7.603B × 58.0% = $4.410B.
- Bull revenue: $6.132B × 1.10 × 1.09 × 1.08 × 1.07 × 1.06 = $9.006B. Bull RNF: $9.006B × 63.0% = $5.674B.

The probabilities are deliberately non-uniform: **30% bear, 55% base, and 15% bull**. Base receives the highest weight because already-cleared capacity auctions, the Clinton contract, the PTC horizon and verified fleet reliability support continued RNF. Bear is twice the bull weight because the observed Q1 pass-through dilution, the 2027 multi-plant support transition, nuclear outage risk and market redesign can impair the forecast independently, whereas the bull requires high availability, load conversion, contract wins and uprates to work together. The weights sum to 100% and do not treat the operating mechanisms as independent probability draws.

These probabilities imply probability-weighted horizon Midwest revenue of **$7.281 billion** and probability-weighted horizon RNF of **$4.151 billion** as descriptive expected values. Those are not separate scenarios and should not be substituted for the base case in the consolidated valuation.

11. Key risks and wildcards

Nuclear reliability and safety tail risk — primarily bear

The business model assumes exceptionally high asset availability. An extended outage at a large unit can remove high-contribution owned output and force replacement purchases at exactly the wrong time. A fleet-wide equipment issue, regulatory inspection, fuel defect, cooling-water constraint, or safety event could affect multiple units or prolong outages. The downside is nonlinear because the segment loses generation value while keeping substantial fixed costs below RNF. Monitoring should focus on capacity factor, unplanned outage days, refueling duration, NRC findings, and replacement-power exposure.

CMC/ZEC expiration and contract replacement — bear/base

Illinois support for Braidwood, Byron, Dresden, Clinton, and Quad Cities reaches a key May 2027 boundary under the current program schedule. Clinton has a disclosed 20-year Meta replacement beginning June 2027; comparable replacement economics are not disclosed for every other unit. The CMC is a two-way settlement: CEG's 2025 Form 10-K reports an average negative $7.58/MWh CMC price in 2025 versus positive $8.05/MWh in 2024, so strong market prices can turn support into a payment rather than an additive subsidy [2025 Form 10-K MD&A pp. 66-68]. The transition could improve value if market and contract prices are strong, but it could also expose plants to more merchant volatility or create unfavorable

contract resets. The base assumes a manageable transition, not a seamless full-fleet repricing.

Federal PTC interpretation, phase-down, and expiry — all cases

Section 45U supports qualifying production through 2032 under current law, covering the 2031 horizon. Its gross-receipts reduction means it does not provide full additive value in strong markets. Tax guidance, wage compliance, gross-receipts definitions, transfer/direct-pay mechanics, or future legislation can change realized value. Bear depends on the floor functioning; bull depends on market value exceeding lost credit. Either case can be wrong if the interaction is modeled additively.

PJM/MISO capacity-market redesign — all cases

Tight PJM auctions and high seasonal MISO prices invite political and regulatory intervention. Caps, floors, must-offer rules, accreditation, demand-response treatment, large-load integration, or cost-allocation changes can redistribute value. PJM capacity auctions procure accredited capacity for specified delivery years; they do not establish an energy price or a perpetual 2031 annuity. MISO's 2026/27 $424.30/MW-day North/Central summer result annualizes to $126.19 because fall, winter and spring cleared at only $33.92, $35.97 and $7.61 [MISO 2026/27 PRA official results](https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260428754715.pdf). The model therefore gives near-term credit to scarcity without applying the headline summer price to all seasons or carrying PJM caps through the horizon.

Data-center and large-load realization — bull/base/bear

Official forecasts show exceptional growth, but project pipelines can double count prospects or omit financing, transmission, transformer, permitting, chip-supply, water, and local opposition constraints. MISO explicitly notes that large loads want 18-36 month connections while generation and transmission take longer. Some loads may use on-site generation or flexible demand, reducing grid purchases. Bull requires conversion; bear assumes substantial attrition.

Hedge roll and basis/load-shape risk — primarily bear

Hedges protect prompt economics but can defer upside and do not perfectly match plant node, customer zone, hourly shape, congestion, capacity, or ancillary exposure. The exact current Midwest hedge percentage is not disclosed. A segment can be "hedged" at the hub and still suffer from node-to-hub basis, outage replacement, or load-shape mismatches. Outer-year hedge renewal is a material uncertainty.

Customer concentration and contract enforceability — bear/base

Long-term contracts improve visibility but can concentrate credit, renegotiation, curtailment, development, and regulatory risk. Clinton/Meta is a major anchor, yet contract price and remedies are confidential. New data-center deals can require transmission, interconnection, and regulatory conditions. Revenue should be recognized only as milestones become binding and deliverable.

Uprate execution — bull/base

Braidwood, Byron, and Clinton uprates offer attractive incremental output because they use existing sites and interconnections. They still require equipment, outage integration, regulatory acceptance, and capex. Delays reduce the bull case; cost overruns fall below RNF and therefore may not be visible in this segment appendix even if revenue arrives. Synthesis must retain the associated capex and D&A rather than valuing output alone.

Commodity price and fuel risk — all cases

Higher power prices can improve market receipts but reduce PTC and state-support value; lower power prices can raise support but may not compensate for all basis, shape, or procurement losses. Nuclear fuel is less volatile than gas but is not costless, and uranium conversion/enrichment supply chains can tighten. Because realized regional prices are not disclosed, the appendix avoids a false $/MWh revenue bridge.

Regulatory license and environmental risk — primarily bear

The horizon fits within the current operating life of the major stations, but continued operation depends on NRC compliance, subsequent license-renewal processes where relevant, environmental permits, cooling-water rules, decommissioning funding, and state/local acceptance. A single adverse decision can destroy more value than several years of normal revenue growth create.

Retail and purchased-power mix — bear/base

Revenue can grow through customer acquisition while RNF margin falls if the portfolio relies on purchased power or wins low-spread load. Q1 FY2026—23.4% revenue growth with a 49.3% RNF margin—is the clearest recent warning [data_package §5, Midwest Q1'26 row]. The kill signal is sustained revenue growth without RNF growth, especially when accompanied by weaker fleet availability or rising purchased-power costs.

Summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	$5.828B	RNF (Operating revenues net of Purchased power and fuel expenses)	50.0%	$2.914B	30%
Base	$7.603B	RNF (Operating revenues net of Purchased power and fuel expenses)	58.0%	$4.410B	55%
Bull	$9.006B	RNF (Operating revenues net of Purchased power and fuel expenses)	63.0%	$5.674B	15%

Midwest is CEG's strongest legacy RNF engine, protected by hard-to-replace nuclear assets, high fleet reliability, capacity scarcity, policy floors and emerging long-term clean-power demand. Its moat is real, but the apparent simplicity of "more load plus scarce nuclear" hides material non-additivity: high energy and capacity receipts reduce PTC or state-credit value; the Meta PPA replaces Clinton's expiring ZEC rather than creating a second full payment; growing retail revenue can carry low spreads; and RNF excludes the large O&M, D&A, tax and capital costs that synthesis must forecast. The revised base case therefore compounds revenue at 4.4% and RNF at 3.5%, with a 58.0% terminal RNF margin below TTM. Bull still earns meaningful upside through scarcity, contracts and uprates, while bear now permits both lower gross receipts and margin compression. No corporate/unallocated or statutory bridge line is allocated to Midwest.

Appendix B3 - Other Power Regions

Other Power Regions — Segment Deep Dive

Company: Constellation Energy Corporation (CEG) **Forecast anchor:** TTM ended March 31, 2026 **Exact horizon:** March 31, 2031, exactly five calendar years after the anchor **Exact segment profit basis: RNF (Operating revenues net of Purchased power and fuel expenses) Evidence boundary:** August 6, 2026, 09:02:30 SGT; Q2 FY2026 is excluded

This appendix forecasts one issuer reportable segment on the QFR-sealed basis. RNF is a gross-margin-like segment performance measure after purchased power and fuel; it is not statutory operating income. No corporate/unallocated RNF, operating and maintenance expense, depreciation, tax, interest, or other statutory-bridge item is allocated here. Those lines belong in the consolidated synthesis.

0. Segment boundary and taxonomy note

Other Power Regions is the legacy geographic reportable segment covering New England, South, West, and Canada. The five legacy geographic segments were stable through FY2025; the January 7, 2026 Calpine acquisition added a sixth reportable segment but did not restate Other Power Regions. Accordingly, FY2021-FY2025 Other Power Regions history is comparable on the issuer's geographic taxonomy, while the segment's own internal mix is not separately disclosed in dollars. The data package also warns that FMP's product endpoint merely repeats geographic regions and is classification-mixed, so official Note 5 figures—not an invented product hierarchy—control [data_package §1, reporting structure and taxonomy].

1. What this segment actually is

Other Power Regions is best understood as a multi-market generation-and-customer portfolio rather than a single product. It collects CEG's legacy activities outside the four separately reported core power markets: eastern PJM in Mid-Atlantic, western PJM/non-South MISO in Midwest, NYISO in New York, and ERCOT in Texas. What remains is economically heterogeneous: New England has an organized energy, ancillary-services, and capacity market with acute winter gas constraints; the South includes markets where bilateral contracting, vertically integrated utility structures, SPP or MISO-South constructs, and resource-adequacy requirements can matter more than a single centralized capacity price; the West combines energy-market exposure with large renewable, storage, hydro, carbon, and resource-adequacy overlays; and Canada includes provincial systems whose wholesale and contract frameworks differ materially by province. CEG does not publish the revenue or RNF weight of those four internal geographies [data_package §1, Other Power Regions row; §4, Other Power Regions row].

The customer proposition is a portfolio of electricity supply, generation output, environmental products, capacity and ancillary value, and risk management. The data package describes each legacy geographic segment as combining owned generation and customer-facing activity by market. A retail or commercial load contract can therefore reduce the segment's merchant exposure but does not eliminate commodity risk: CEG still must match generation, hedges, and purchased power against customer load shape. Revenue can rise simply because wholesale prices or purchased-power costs rise, while RNF may fall if procurement cost rises faster or hedges are out of position. That is why revenue alone is a poor proxy for economic growth here.

The pricing model varies by activity. Owned generation earns energy and, where available, capacity and ancillary revenue; long-term PPAs and customer contracts exchange some upside for visibility; retail supply earns a spread after purchased power, shaping, congestion, credit, and servicing costs; renewable assets may earn energy, environmental attributes, or contracted payments; hydro and pumped-hydro can earn both energy and flexibility value; and nuclear output can benefit from high capacity factors, contracted clean-energy demand, and the federal nuclear production tax credit, although the credit phases down as eligible gross receipts rise. The segment disclosure does not permit a dollar allocation among these engines. This appendix therefore forecasts one additive segment line and uses the engines as driver tests rather than fabricating sub-product financial statements.

Go-to-market is likewise portfolio-based. CEG can sell directly to commercial and industrial customers, participate in wholesale markets, transact through bilateral contracts, and manage exposure through its ratable hedging program. At the combined-company level, management said the customer platform serves approximately 275 million MWh of electricity and 800 Bcf of natural gas annually, but this scale is not allocated to Other Power Regions [data_package §6, Q1 FY2026 customer-scale row]. The segment may benefit from the company's broader origination capabilities, yet none of the public figures permits an analyst to claim that a particular percentage of those volumes belongs here.

The practical investor takeaway is that Other Power Regions should not be modeled as “New England power prices times volume.” New England is visible in the company's reference-price disclosure, but South, West, Canada, retail procurement, hedge settlements, renewable capture, hydro conditions, nuclear availability, capacity payments, and contract rollovers can offset or amplify it. The segment's low and volatile RNF margin relative to CEG's nuclear-heavy core regions is consistent with a larger share of pass-through purchased power and a more mixed generation/customer book, but CEG does not disclose enough internal detail to quantify that inference.

2. Current economics

TTM revenue was **$5.514 billion** and TTM RNF was **$0.892 billion**, implying a **16.2% RNF margin** [data_package §3, Other Power Regions Revenue row; RNF row; RNF margin row]. FY2025 revenue was $5.583 billion, up 1.4%, while RNF declined to $0.819 billion from $1.268 billion and the RNF margin fell to 14.7% from 23.0% [data_package §3, Other Power Regions Revenue, YoY, RNF, and RNF margin rows]. The TTM bridge is not a sum of rounded quarterly display values: the sealed computation is FY2025 RNF of $819 million less Q1 FY2025 RNF of $194 million plus Q1 FY2026 RNF of $267 million, or $892 million [data_package §3a, TTM bridge note]. The specific controlling primary sources are Note 5 of CEG's [FY2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm) and Note 5 of its [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm); the QFR-sealed same-window reconciliation resolves the $1 million difference between rounded quarterly display values and the controlling TTM RNF.

The latest four reported quarters show why a single annual margin can mislead. Q2 FY2025 produced $1.178 billion of revenue and $181 million of RNF, a 15.4% margin; Q3 produced $1.543 billion and $343 million, or 22.2%; Q4 produced $1.306 billion and $102 million, or 7.8%; and Q1 FY2026 produced $1.487 billion and $267 million, or 18.0% [data_package §5, Other Power Regions Q2'25 through Q1'26 rows]. The specific sources are Note 5 of the Q2 FY2025 and Q3 FY2025 Forms 10-Q, FY2025 less nine-month Note 5 for Q4, and Note 5 of the Q1 FY2026 Form 10-Q, as identified in data_package §5. Q1 revenue declined 4.4% year over year, but the quarter's RNF margin exceeded the FY2025 margin. This dispersion is evidence of weather, price, hedge, capacity-period, procurement, and geographic-mix effects—not evidence of a stable quarterly run rate.

The finest consistent dollar disclosure is the segment total itself. The issuer does not provide New England, South, West, or Canada revenue/RNF; it does not disclose Other Power Regions revenue by generation technology; and it does not allocate retail volumes or customer counts. [DATA GAP: Other Power Regions revenue, RNF, owned capacity, generation output, retail load, and contract coverage by New England/South/West/Canada or by nuclear/renewables/hydro/retail are not separately disclosed; the forecast therefore uses one segment line.] No product dollars are back-solved [data_package §4, disclosure-method note].

Capital intensity is real but not segment-measurable. Generation requires maintenance outages, major components, environmental compliance, interconnection and transmission spending, and in some technologies periodic life-extension or relicensing investment. Customer supply requires less physical capital but needs collateral, credit, risk systems, and liquidity during volatile periods. CEG does not disclose maintenance versus growth capex by this segment, nor does the statutory bridge allocate operating and maintenance or depreciation into Other Power Regions [data_package §3a, forecast-driver ledger; §10, maintenance-versus-growth-capex gap]. Therefore this appendix does not convert RNF into a segment free-cash-flow margin or claim a segment ROIC.

Portfolio-level operating indicators provide context but not allocation. CEG reported a 94.7% fleet nuclear capacity factor and 183 TWh of nuclear output in FY2025, with nuclear representing 68% of company electric supply. Legacy renewable capture was 96.6%, while the gas/oil/pumped-hydro fleet's dispatch-match metric was 97.9% [data_package §0a, historical operating KPI series]. Those figures show high fleet execution, and they inform the range of possible drivers inside a mixed geographic portfolio, but they are not labeled as Other Power Regions KPIs. The model accordingly gives reliability a role in margin scenarios without assigning segment-specific capacity or output.

3. Unit economics

The core equation is simple but the drivers are not:

RNF = operating revenues − **purchased power expense** − **fuel expense.**

For owned nuclear, hydro, wind, solar, gas, or oil generation, revenue depends on output, realized energy prices, capacity/ancillary payments, environmental attributes, and hedges. Purchased power and fuel are lower for fuel-free nuclear,

hydro, wind, and solar than for thermal generation, but outages can force replacement purchases precisely when market prices are high. Gas and oil generation can benefit when scarcity or ancillary pricing is strong, yet spark spreads, transport constraints, emissions costs, and unit availability determine whether higher energy prices translate into RNF. Hydro adds water-availability risk; pumped hydro adds charge/discharge spread and cycling economics; intermittent renewable output adds capture-price and curtailment exposure; nuclear adds outage and regulatory risk but provides high-load-factor, carbon-free baseload.

For retail and commercial supply, the starting point is customer revenue under fixed-price, indexed, block-and-index, or other bilateral arrangements. The cost side includes purchased energy, capacity, transmission/congestion, ancillary services, renewable obligations, balancing, and shaping. Gross dollars can expand in an inflationary or high-price environment with little improvement in RNF. A disciplined portfolio earns a margin for origination, credit, structuring, and risk management; a mismatch between contracted load and generation/hedges creates losses. This mechanism helps explain why Other Power Regions' revenue history is far more volatile than a normal volume-growth business.

Hedges shift timing rather than eliminate economics. The company historically used a three-year ratable sales plan at approximately 90%/60%/30% for successive forward years, while later disclosure emphasized that a $5/MWh reduction was largely immaterial for the next two years because of hedge and nuclear-PTC protection [data_package §0a, hedges, contracted load, and PPAs]. Outer-year exposure remains. A strong current market can therefore lift quoted future value before it appears in RNF, and a weak market may take time to flow through. Conversely, a hedge entered before a price spike can cap immediate upside.

The nuclear production tax credit acts as a floor, not free incremental upside. When eligible nuclear gross receipts are low, the credit can cushion RNF; when power and capacity receipts rise, the credit phases down. The bear case thus should not extrapolate a full merchant-price decline into RNF, while the bull case should not add the entire power-price increase on top of an unchanged credit. This negative covariance dampens both tails.

Capacity value varies dramatically by market. New England's Forward Capacity Market compensates qualifying availability. ISO New England's FCA 18, for the 2027/2028 commitment period, cleared at $3.58/kW-month versus $2.59 in FCA 17; 31,556 MW cleared against a 30,550 MW net installed-capacity requirement ([ISO-NE FCA 18 results](https://www.iso-ne.com/static-assets/documents/100008/20240209_pr_fca18_initial_results.pdf)). Other southern, western, or Canadian systems use different constructs. The segment cannot be modeled with one uniform capacity price.

Margin can expand if high availability allows CEG to capture energy/capacity value, renewable capture remains strong, retail hedges are well matched, hydro conditions are normal, and more volume moves under long-term contracts with attractive fixed margins. It can contract if gas basis or emissions costs rise without matching revenue, renewable curtailment depresses capture prices, hydro conditions are poor, a nuclear or thermal outage triggers costly replacement purchases, retail load is mis-shaped, or low-price contract renewals replace richer legacy positions.

The historical RNF margin range demonstrates the sensitivity: 13.7% in FY2022, 21.2% in FY2023, 23.0% in FY2024, 14.7% in FY2025, and 16.2% in the TTM [data_package §3, Other Power Regions RNF margin row]. A five-year forecast that simply holds the peak or trough would be false precision. The base case normalizes modestly above TTM; bear and bull deliberately preserve a wide distribution.

4. Competitive dynamics

New England

New England is an organized but fuel-constrained market where nuclear, gas, imports, demand resources, renewables, storage, and hydro compete across energy, capacity, and ancillary products. ISO New England's internal market monitor found 2025 outcomes broadly competitive even as total wholesale costs rose nearly 50% to about $15 billion. Gas was the main driver: annual regional gas prices exceeded $6/MMBtu, up 105%, and constrained Northeast hubs increased more than national benchmarks. Net imports fell to their lowest level in more than a decade because of reduced Canadian hydro availability and outages, forcing greater reliance on internal generation ([ISO-NE 2025 Annual Markets Report](https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf)).

This environment can support the value of reliable, fuel-secure or hedged resources, but it also raises replacement-power and retail-procurement risk. Competition is not only among generators. Behind-the-meter solar changes daytime net load, batteries compete for ramp and ancillary value, imports connect neighboring markets, and demand response competes in capacity. ISO-NE's 2026 CELT final draft projected net annual energy rising from 116.7 TWh in 2026 to 121.1 TWh in 2031, about 0.7% annualized, while the summer 50/50 peak rises from 25,228 MW to 25,906 MW and the winter peak from 20,483

MW to 22,918 MW. Electrification increasingly shifts the region toward winter peaks ([ISO-NE 2026 CELT forecast presentation](https://www.iso-ne.com/static-assets/documents/100034/a4.0_celt2026_finaldraft_pac.pdf)). Demand growth is constructive but not enough on its own to justify a high segment-wide CAGR.

Pricing power in New England is episodic rather than franchise-like. Scarcity, fuel constraints, capacity qualification, and local reliability can create rents, but market monitors, mitigation rules, transmission investment, distributed resources, and new entry constrain them. The segment moat is therefore operational and portfolio-based, not a permanent right to charge a premium.

South

The “South” label is internally broad and CEG does not disclose which submarkets or assets contribute how much revenue. For competitive context, SPP illustrates the principal tensions in southern and central organized markets. Its market monitor said 2025 energy consumption increased 3%, mostly from load growth; data centers and crypto mining affected load patterns; wind provided 38% of generation; and the market remained competitive. Renewable, storage, and hybrid projects still represented 76% of a roughly 149 GW interconnection queue, although gas requests rose sharply to 35 GW ([SPP 2025 State of the Market](https://www.spp.org/documents/76798/2025_annual_state_of_the_market_report.pdf)).

SPP's 2026 summer adequacy report shows why both scarcity and competition belong in the model. Existing resources alone would become deficient in 2029 and reach an 11,188 MW capacity deficit by 2031 as net peak demand rises 28% against only 1% growth in existing accredited capacity. Yet nearly 22,000 MW of anticipated gas, solar, and battery additions could instead lift the 2031 reserve margin to 22.9%; completion risk determines which outcome prevails ([SPP 2026 Summer Resource Adequacy Report](https://spp.org/documents/76932/2026%20spp%20summer%20resource%20adequacy%20report.pdf)).

For CEG, this is a two-sided competitive dynamic. Fast load growth and delayed interconnections can create strong energy, capacity, bilateral-contract, or flexibility value. But successful gas, solar, storage, transmission, and demand-response buildout can quickly compete it away. Retail suppliers also face well-capitalized utilities, independent generators, commodity traders, and specialist energy retailers. The base case assumes moderate load growth but no permanent scarcity rent.

West

Western markets combine rapid demand growth with very rapid resource additions. CAISO's approved 2025-2026 transmission plan uses forecasts of 15 GW of California load growth by 2035 and 20 GW by 2040, driven by electrification, manufacturing, and large loads including data centers. The plan enables large amounts of solar, wind, geothermal, storage, and imported wind ([CAISO transmission-plan release](https://www.caiso.com/about/news/news-releases/iso-board-of-governors-approves-2025-2026-transmission-plan)).

The same buildout pressures capture prices. CAISO's market monitor reported that wind/solar downward dispatch increased 22% in 2025, including about 4,780 GWh of economic curtailment. Battery capacity reached about 25,700 MW, with average evening discharge peaking near 9,100 MW. Day-ahead prices averaged about $39/MWh and WEIM 15-minute prices about $34/MWh, down 14% year over year despite higher gas prices. Hypothetical new gas units' energy-market revenues remained below estimated going-forward fixed costs, pointing to the continuing importance of long-term contracts ([CAISO 2025 Annual Report on Market Issues and Performance](https://www.caiso.com/documents/2025-annual-report-on-market-issues-and-performance.pdf)).

These facts argue against treating renewable capacity growth as automatic RNF growth. Wind and solar volume can increase while midday capture prices fall; storage can monetize spreads while also narrowing them; hydro's value depends on water conditions and interregional congestion; carbon costs vary by jurisdiction; and reliable gas or nuclear capacity can earn scarcity value yet require contracts or resource-adequacy payments to cover fixed cost. CEG's competitive advantage is the ability to bundle generation, customer load, risk management, and contracts across these conditions, not ownership of any single technology.

Canada

Canada is not one market. Provincial systems differ in market design, regulation, hydrology, generation mix, and procurement. Ontario's IESO launched its renewed wholesale market on May 1, 2025, adding a day-ahead market and locational marginal pricing to increase operational and financial certainty and reflect transmission constraints ([IESO renewed market operations](https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Renewed-Market-Operations)). The transition can improve price signals but also creates basis, settlement, and implementation risk for market participants.

Ontario's 2025 planning outlook projected net annual energy demand from 157 TWh in 2026 to 262 TWh in 2050, a 2.2% CAGR. It expected strong 2026-2030 industrial demand and later data-center growth; commercial data-center energy alone was forecast from 3 TWh in 2026 to 16 TWh in 2050. The outlook also projected summer peak demand at a 1.7% CAGR and winter peak at 1.9% ([IESO 2025 Annual Planning Outlook](https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf)). Demand is supportive, but provincial procurement, nuclear refurbishment, hydro availability, conservation, new generation, transmission, and contract structures determine who captures value.

Hydro is both competitor and complement. Strong Canadian hydro conditions can increase supply and imports, suppressing regional prices; weak hydrology can reduce imports and tighten New England, as occurred in 2025. Nuclear can provide high-capacity-factor clean output but competes for long-duration clean-energy contracts. Retail and commercial portfolios compete on credit, structure, customer service, and commodity risk. The result is an integrated but volatile opportunity set, not a smooth secular-growth line.

5. Moat at the segment level

Other Power Regions has a **moderate portfolio moat, not a strong regional monopoly moat**. The defendable pieces are scale, fleet and fuel diversity, dispatch and outage execution, credit capacity, collateral access, risk systems, origination, and the ability to match generation with customer load. These capabilities are costly to assemble and allow CEG to sell structures that a single-asset generator or small retail supplier may not be able to offer. Company-wide renewable capture of 96.6% in FY2025 and high nuclear capacity factors support an operational credibility argument [data_package §0a, historical operating KPI series].

Long-term contracting can turn operational capability into durable economics. Management described long-term contracts as an ordinary part of strategy and said more than 10,000 MW of the combined fleet had executed deals [data_package §6, Q2 FY2025 contract-strategy row; Q4 FY2025 contracted-fleet row]. However, no disclosed figure assigns those contracts to Other Power Regions. [DATA GAP: The share of Other Power Regions MW, generation, retail load, or RNF under long-term contracts is not disclosed.] Contracting should therefore support the bull mechanism only generally, not as a quantified backlog.

The moat is weakened by transparent commodity markets and sophisticated competitors. ISO/RTO rules reduce product differentiation; utilities, independent power producers, retailers, traders, and financial hedgers can compete. Renewable and storage entry can compress energy spreads. Transmission can relieve local scarcity. Regulators can change capacity accreditation, carbon costs, retail rules, market caps, or contract treatment. Customer switching makes retail share contestable unless service and structure create loyalty.

Asset diversity can also hide adverse selection. A portfolio spanning New England, South, West, and Canada may reduce single-market volatility, but management could retain difficult assets or customer books whose gross revenue disguises weak RNF. Because internal geography and technology margins are not disclosed, outsiders cannot verify whether the low consolidated margin is a diversified equilibrium or the sum of several fragile exposures. This opacity deserves a valuation discount relative to segments with clearer asset economics.

Over five to ten years, the moat should preserve participation but not guarantee excess returns. The base case assumes RNF margin stabilizes near 17%, slightly above TTM but well below the FY2024 peak. The bull case requires contracts, load growth, and flexibility value to outweigh renewable capture-price pressure and new entry. The bear case assumes the portfolio's diversification fails to protect against simultaneous contract roll-down, weak capture prices, fuel/basis stress, and replacement-power costs.

6. Historical growth rates

CEG does not disclose an additive product hierarchy beneath this segment. The only dollar-disclosed financial line is the regional generation and customer portfolio. Historical dollars below reproduce official data-package values; the CAGR is calculated from the FY2022 and FY2025 cells in the same row. No value is back-solved. The annual source trail is the Other Power Regions row in Note 5 of the [FY2022 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm), [FY2023 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827524000014/ceg-20231231.htm), [FY2024 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827525000023/ceg-20241231.htm), and [FY2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm), all inventoried in data_package §0a; official Note 5 values control over the classification-mixed FMP product endpoint.

Product / sub-segment	FY2023 rev	FY2024 rev	FY2025 rev	3-yr CAGR FY2022-FY2025	Most recent annual YoY	Data package cite
Other Power Regions regional generation and customer portfolio	$5.851B [data_package §3, Other Power Regions Revenue row]	$5.506B [data_package §3, Other Power Regions Revenue row]	$5.583B [data_package §3, Other Power Regions Revenue row]	(6.0%) from $6.732B FY2022 to $5.583B FY2025 [data_package §3, Other Power Regions Revenue row]	1.4% [data_package §3, Other Power Regions YoY row]	[data_package §4, Other Power Regions row]

Arithmetic checks. FY2022 $6.732B × (1 − 13.1%) = $5.850B versus disclosed FY2023 $5.851B, a 0.0% rounding difference. FY2023 $5.851B × (1 − 5.9%) = $5.506B, matching FY2024. FY2024 $5.506B × (1 + 1.4%) = $5.583B, matching FY2025. All annual checks are within the required 2% tolerance. The TTM revenue anchor of $5.514B is a separate same-window measure and is not substituted for the FY2025 annual value [data_package §3, Other Power Regions table].

The history does not show a conventional secular-growth pattern. Revenue surged 37.7% in FY2022, fell 13.1% in FY2023, fell 5.9% in FY2024, and rose 1.4% in FY2025. RNF did not move in lockstep: it rose from $0.921B in FY2022 to $1.240B in FY2023 and $1.268B in FY2024 before falling to $0.819B in FY2025 [data_package §3, Other Power Regions YoY and RNF rows]. The correct forecast starting point is normalized regional demand and portfolio economics, not the negative trailing revenue CAGR alone.

7. Management guidance

The data package contains no guidance stated specifically for Other Power Regions. [DATA GAP: Management has not disclosed an Other Power Regions revenue, RNF, margin, volume, hedge-coverage, capacity, or capex guide in data_package §6.] The relevant company-level statements are retained as qualitative anchors only:

- **Q2 FY2025 call, August 7, 2025; Joe Dominguez — contract strategy.** “long-term contracts like our Meta and Microsoft deals” are becoming “an ordinary part of our strategy” [data_package §6, contract-strategy row]. Interpretation: contracting can reduce merchant variance, but neither contract is assigned to this segment in the verified taxonomy; no Other Power Regions dollars are added.
- **Q4 FY2025 call, March 31, 2026; Joe Dominguez — contracted fleet.** “executed deals for over 10,000 megawatts of our fleet” [data_package §6, contracted-fleet row]. Interpretation: company-wide visibility is improving, but the absence of a segment allocation prevents a backlog conversion model.
- **Q4 FY2025 call, March 31, 2026; Shane Smith — growth projects.** “$3.9 billion in growth projects” with “returns of at least 10% on an unlevered basis” [data_package §6, growth-capex row]. Interpretation: future projects can add output and contracts, but the segment receives no project dollars without a disclosed assignment.
- **Q1 FY2026 call, May 11, 2026; Shane Smith — customer scale.** “approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually” [data_package §6, customer-scale row]. Interpretation: the combined commercial platform offers origination and cross-sell scale; this is a company denominator, not Other Power Regions volume.

Management also affirmed FY2026 adjusted operating EPS of $11.00-$12.00, but that is neither an RNF guide nor a segment guide and is not used to set this margin [data_package §6, guidance note]. The scenario design gives greater weight to observable market drivers and the segment's own history than to unallocated corporate aspirations.

8. Forward growth assumptions

Base case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Base CAGR TTM to TTM+5y	Justification
Other Power Regions regional generation and customer portfolio	(6.0%) [data_package §3, Revenue row]	Q1'26 (4.4%) [data_package §5, Q1'26 row]	Not separately guided [data_package §6]	2.0%	Moderate load/electrification and contracts offset mature supply, competition, and capture-price pressure. Revenue remains a weak RNF proxy.

The base case starts below a broad 2%-3% demand-growth narrative because New England's 2026 CELT shows only about 0.7% annual energy growth to 2031, while Ontario's long-run 2.2% demand CAGR and western/southern large-load growth are offset by undisclosed mix, energy-efficiency, new entry, and retail pass-through effects. Annual growth ramps from 1.5%

to 2.5% and then settles at 2.0%; there is no abrupt rebound from Q1's 4.4% decline. The $5.514B anchor compounds to $6.088B on March 31, 2031.

Bull case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bull CAGR TTM to TTM+5y	Justification
Other Power Regions regional generation and customer portfolio	(6.0%) [data_package §3, Revenue row]	Q1'26 (4.4%) [data_package §5, Q1'26 row]	Not separately guided [data_package §6]	4.5%	Faster data-center/industrial load, delayed supply, more contracts, and stronger flexibility value outweigh renewable curtailment and competition.

The bull case is not a return to FY2022's 37.7% spike. Instead, growth builds from 3.5% to 5.0% as large loads connect, regional capacity tightens, and CEG converts portfolio scale into contracted supply. ISO-NE winter electrification, SPP's potential existing-resource deficit, California's 15 GW load-growth forecast by 2035, and Ontario's industrial/data-center growth are supportive. The case still caps CAGR at 4.5% because more than 20 GW of anticipated SPP additions, 74 GW of California resource additions by 2035, and expanding batteries/renewables are formidable supply responses.

Bear case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bear CAGR TTM to TTM+5y	Justification
Other Power Regions regional generation and customer portfolio	(6.0%) [data_package §3, Revenue row]	Q1'26 (4.4%) [data_package §5, Q1'26 row]	Not separately guided [data_package §6]	(2.0%)	Contract roll-down, weak renewable capture, mild demand, and aggressive new entry outweigh inflationary revenue pass-through.

The bear case declines 4%, 3%, 2%, and 1% before stabilizing. This is milder than the FY2023 annual decline of 13.1% but sustained for longer, reflecting multiple adverse mechanisms rather than a one-year commodity reset. Successful renewable/storage/gas entry compresses market value; retail competition reduces spread; hydro and imports suppress scarcity during favorable conditions; and basis or outage costs prevent revenue from translating into RNF. The endpoint is $4.982B.

Explicit year-by-year path

Case	2027-03-31 growth / revenue	2028-03-31 growth / revenue	2029-03-31 growth / revenue	2030-03-31 growth / revenue	2031-03-31 growth / revenue	Five-year CAGR
Bear	(4.0%) / $5.293B	(3.0%) / $5.135B	(2.0%) / $5.032B	(1.0%) / $4.982B	0.0% / $4.982B	(2.0%)
Base	1.5% / $5.597B	2.0% / $5.709B	2.5% / $5.851B	2.0% / $5.968B	2.0% / $6.088B	2.0%
Bull	3.5% / $5.707B	4.5% / $5.964B	5.0% / $6.262B	5.0% / $6.575B	4.5% / $6.871B	4.5%

The terminal revenue figures are mechanical scenario outputs, not externally sourced targets. Starting from the sealed $5.514B TTM anchor, the exact unrounded endpoints are $4.981625B bear, $6.087755B base, and $6.870974B bull; their exact five-year CAGRs are (2.010%), 2.000%, and 4.499%, respectively, which render to the displayed one-decimal CAGRs and three-decimal dollar values. Applying the scenario margins to those unrounded revenue endpoints produces exact RNF of $0.597795B, $1.034918B, and $1.511614B, which render to $0.598B, $1.035B, and $1.512B. The regional demand, supply, contracting, and capture-price evidence constrains the annual rates, but the rates are not falsely represented as a weighted average of undisclosed New England/South/West/Canada revenue.

Heterogeneous driver overlay without fabricated allocations

Driver area	Bear mechanism	Base mechanism	Bull mechanism	Financial treatment
New England	Supply/contract competition and weak scarcity	Slow energy growth; winter peak supports flexibility	Fuel constraints and delayed supply lift capacity/flex value	Included qualitatively; no region dollars
South	New gas/solar/storage arrive on time	Load and supply grow together	Large loads outrun interconnection build	Included qualitatively; no region dollars
West	Curtailment and batteries compress capture	Contracts offset weak energy-only returns	Large-load growth and transmission scarcity create value	Included qualitatively; no region dollars
Canada	Strong hydro/new procurement suppress prices	Demand growth and market renewal normalize value	Data-center/industrial load plus tight supply	Included qualitatively; no province dollars

Driver area	Bear mechanism	Base mechanism	Bull mechanism	Financial treatment
Nuclear	Outage/replacement purchases; PTC only partial cushion	High availability and PTC floor	Clean contracts and high availability; PTC phases down	No segment nuclear MW allocation
Renewables/hydro	Poor capture or unfavorable water/curtailment	Normal capture and hydrology	Scarcity, environmental attributes, flexibility	No technology revenue allocation
Retail/customer	Load mismatch and price competition	Disciplined hedging and stable spreads	Cross-sell and structured contracts expand margins	No segment retail-load allocation

The overlay is intentionally non-additive. It prevents a common error: assigning equal weights to four geographies and then summing unsupported sub-forecasts. Only the segment line is financially modeled.

9. Forward RNF margin assumptions

Exact metric: RNF (Operating revenues net of Purchased power and fuel expenses). Current TTM RNF margin is 16.2% [data_package §3, Other Power Regions RNF margin row].

Case	TTM RNF margin	TTM+5y RNF margin	Change	Specific mechanism
Bear	16.2%	12.0%	(420 bps)	Contract roll-down, retail mismatch, capture-price pressure, outage replacement power, fuel/basis and carbon costs
Base	16.2%	17.0%	80 bps	Normalized hedges, stable availability, modest contracting, and regional diversification offset competition
Bull	16.2%	22.0%	580 bps	Strong capacity/flexibility value, high availability, attractive long-term contracts, and disciplined retail procurement

The bear margin is below FY2022's 13.7% and the recent Q4 FY2025 margin of 7.8% sits below even this annual endpoint [data_package §3, RNF margin row; §5, Q4'25 row]. The bear does not extrapolate 7.8% indefinitely because geographic diversification, hedging, and the nuclear PTC provide partial cushions, but it assumes several adverse conditions overlap. At $4.982B of revenue, 12.0% produces $0.598B of RNF.

The base margin is only 80 bps above TTM and below FY2023-FY2024 margins of 21.2%-23.0%. This is deliberate. Normalization from a weak FY2025 and mixed TTM can restore some spread, yet rapid renewable/storage entry and retail competition prevent a full return to peak. At $6.088B, 17.0% yields $1.035B.

The bull margin of 22.0% is near, but not above, the FY2024 peak. The 580 bps expansion requires more than higher power prices: contracts must protect fixed-cost recovery, availability must remain high, capacity/ancillary/flexibility payments must strengthen, retail procurement must stay matched, and renewable/hydro capture must be acceptable. The federal nuclear PTC phase-down prevents double-counting high market prices with a full subsidy. At $6.871B, 22.0% yields $1.512B.

No product-level margin weighting is possible because CEG does not disclose additive New England/South/West/Canada or nuclear/renewable/hydro/retail revenue and RNF. A purported revenue-weighted internal margin would be invented. The segment-level margin is the only reconstructable basis. Consequently, each scenario's RNF is calculated once—disclosed segment revenue multiplied by its scenario-wide RNF margin—without embedding an unsealed corporate allocation or a hidden internal-geography weighting.

10. Segment rollup

The rollup begins with the sealed TTM revenue of $5.514B and RNF of $0.892B. Because the segment has one disclosed additive line, product revenue equals segment revenue by construction. Endpoint RNF is revenue multiplied by the scenario RNF margin; all totals reconcile exactly within rounding.

Case	Disclosed modeled line TTM+5y revenue	Segment TTM+5y revenue	RNF margin	RNF	Revenue tie-out	Profit tie-out
Bear	$4.982B	$4.982B	12.0%	$0.598B	100.0%	$4.982B × 12.0% = $0.598B

Case	Disclosed modeled line TTM+5y revenue	Segment TTM+5y revenue	RNF margin	RNF	Revenue tie-out	Profit tie-out
Base	$6.088B	$6.088B	17.0%	$1.035B	100.0%	$6.088B × 17.0% = $1.035B
Bull	$6.871B	$6.871B	22.0%	$1.512B	100.0%	$6.871B × 22.0% = $1.512B

The probability set is deliberately non-uniform: **30% bear, 50% base, and 20% bull**. The higher bear weight than bull reflects disclosure opacity, the segment's 35% RNF decline in FY2025, low quarterly visibility, and competitive supply responses. Management tone is constructive on company-wide contracting and customer scale, but management provides no segment guide or contract allocation, so that tone supports the 50% base weight rather than a higher bull weight. The base remains most likely because load growth and portfolio diversity plausibly offset but do not overwhelm mature-market competition. Probability weighting is for synthesis context, not a claim that regional outcomes are independent.

Probability rollup	Weight	TTM+5y revenue	Weighted revenue	RNF margin	TTM+5y RNF	Weighted RNF
Bear	30%	$4.982B	$1.495B	12.0%	$0.598B	$0.179B
Base	50%	$6.088B	$3.044B	17.0%	$1.035B	$0.518B
Bull	20%	$6.871B	$1.374B	22.0%	$1.512B	$0.302B
Total / implied	100%	N/A	$5.913B	16.9% implied	N/A	$0.999B

The probability-weighted endpoint is **$5.913B of revenue and $0.999B of RNF**, calculated from the displayed scenario values at 30%/50%/20%; the implied weighted RNF margin is 16.9% ($0.999B divided by $5.913B). This diagnostic is not a fourth forecast case and should not be used to infer a single margin path. Corporate/unallocated RNF and every statutory operating-expense or below-line item remain outside this appendix.

11. Key risks and wildcards

[Bear] Internal-mix opacity. The largest analytical risk is that New England, South, West, Canada, generation technologies, and retail have materially different margins, yet CEG publishes only one segment total. A favorable aggregate can hide a deteriorating book; a weak quarter can also hide attractive contracted assets. Monitoring requires new segment disclosure, not analyst allocations.

[Bear] Renewable capture and curtailment. CAISO's 22% increase in downward dispatch and rapid battery build show how fast energy value can shift. More renewable MWh need not create more RNF if capture prices fall, curtailment rises, or storage compresses spreads. The relevant trigger is persistent deterioration in RNF despite stable availability and rising system demand.

[Bear] Hydro volatility. Strong hydro output can suppress prices and imports can pressure internal generation; weak hydro can tighten neighboring markets but also reduce owned hydro generation if CEG has exposure. Because Other Power Regions hydro capacity and water conditions are not disclosed, hydrology is a two-sided but unquantified risk.

[Bear] Nuclear or thermal outage. An unplanned outage can reduce generation and force replacement purchases during high-price periods. Portfolio diversification helps only if output, hedges, and retail load are well matched. Company-wide nuclear reliability is strong, but segment-specific unit exposure is not disclosed.

[Bear] Retail load-shape mismatch and credit. Fixed-price customer load can be loss-making if weather, hourly shape, congestion, or capacity costs deviate from hedges. Customer defaults and collateral calls can turn a nominally asset-light activity into a liquidity-intensive one. RNF captures the procurement consequence, but balance-sheet liquidity sits at the consolidated level.

[Bear/Base] Contract roll and basis risk. Long-term contracts improve visibility but can lock in mediocre economics, expire into weak markets, or fail to match nodal generation with customer load. Confidential prices prevent direct underwriting. The base assumes neutral-to-positive renewal economics, not automatic accretion.

[Bear/Base] Market-design change. ISO-NE capacity reforms, SPP accreditation and reserve requirements, CAISO/WEIM evolution, Canadian locational pricing, carbon costs, and retail rules can redistribute rent. A diversified portfolio is exposed to more regulatory regimes, even if it is less dependent on any single one.

[Base/Bull] Load-growth realization. Data centers, electrification, mining, manufacturing, EV supply chains, and building electrification are visible in official forecasts. Projects can be delayed by interconnection, transmission, equipment, financing,

or community opposition. The bull case requires actual energized load, not queue announcements.

[Bull] Delayed supply and transmission. SPP's existing-resource deficit scenario and CAISO's large infrastructure needs show that load can outrun accredited supply. If resource additions or transmission are delayed while CEG maintains reliable output, energy, capacity, ancillary, and bilateral-contract value can exceed the base case.

[Bull] Contracting and customer-platform leverage. CEG's combined origination scale could convert heterogeneous assets into higher-value, longer-duration customer contracts. This becomes a real bull catalyst only if management discloses Other Power Regions MW, duration, pricing framework, or RNF contribution and if contracts protect rather than surrender scarcity value.

[Bull/Bear] Nuclear PTC interaction. The credit cushions low eligible receipts but phases down as gross receipts rise. It narrows downside and caps additive upside. Any model that holds the full credit constant while raising market prices materially would overstate bull RNF.

Monitoring dashboard. The most useful observable signals are quarterly Other Power Regions revenue, RNF, and RNF margin; Q1/Q2 weather and outage outcomes; renewable capture and combined-fleet EFOF; official ISO load forecasts; New England gas and import conditions; capacity-market results; renewable curtailment and battery penetration in the West; resource-accreditation and interconnection progress in the South; and Canadian market-settlement changes. A two-quarter RNF margin below 12% without an explained temporary driver would pull the bear case forward. A disclosed multi-year contract book plus margins sustainably above 20% would increase bull weight.

Scenario summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	$4.982B	RNF (Operating revenues net of Purchased power and fuel expenses)	12.0%	$0.598B	30%
Base	$6.088B	RNF (Operating revenues net of Purchased power and fuel expenses)	17.0%	$1.035B	50%
Bull	$6.871B	RNF (Operating revenues net of Purchased power and fuel expenses)	22.0%	$1.512B	20%

The scenario endpoint is March 31, 2031 exactly. The forecast uses verified CEG historicals, quotes, and classifications only from `data_package.md` and `statutory_bridge.json`. External ISO-NE, SPP, CAISO, and IESO evidence supplies competitive and market-driver context; it does not replace or restate CEG historicals.

Appendix B4 - Calpine

Calpine — Segment Deep Dive

Model anchor: TTM ended March 31, 2026 **Forecast horizon:** March 31, 2031, exactly five calendar years **Exact segment profit basis: RNF (Operating revenues net of Purchased power and fuel expenses)**

0. Segment boundary and taxonomy note

Calpine is a new reportable segment created when Constellation completed the acquisition on January 7, 2026. It did not exist in Constellation's five-segment reporting taxonomy through FY2025. The only CEG-owned Calpine history is the 84-day period from acquisition through March 31, 2026; FY2025's $0 convention is not evidence that the underlying business had no activity. This analysis therefore never compares a pre-acquisition Calpine dollar history with the current segment, never invents a regional or product split, and never treats the 84-day contribution as a normal trailing twelve months. Constellation's exact segment-profit measure is **RNF (Operating revenues net of Purchased power and fuel expenses)**. RNF is not operating income. Corporate and statutory-bridge items, including operating and maintenance expense, depreciation and amortization, taxes other than income taxes, interest, purchase-accounting charges, and unallocated activity, remain outside this segment forecast [Q1 FY2026 Form 10-Q, Note 5, Segment Information; data_package §3a, QFR-sealed forecast-driver ledger].

1. What this segment actually is

Calpine is an integrated competitive-power platform rather than a regulated utility. Its physical core is a fleet of natural-gas-fired generation, supplemented by the Geysers geothermal complex, battery storage, solar, and related assets. Its commercial core sells electricity and natural gas to residential, commercial, industrial, municipal, utility, and wholesale counterparties. The combination lets it use owned generation, purchased power, fuel procurement, hedging, retail load, tolling or capacity arrangements, and long-term contracts as one portfolio.

The customer proposition differs by channel. Wholesale output is sold into organized markets or contracted with utilities and other counterparties. Commercial and industrial customers buy shaped power, gas, renewable attributes, risk management, and increasingly bespoke around-the-clock or on-site solutions. Residential customers buy retail power and gas through brands such as Champion Energy. Large-load customers care about speed to power, deliverability, reliability, clean-energy attributes, and a credible counterparty that can finance interconnection and plant work. The 380 MW CyrusOne agreement at Freestone, with an exclusive second 380 MW phase, illustrates the last category, but contract price and revenue timing are not disclosed [data_package §0a, Hedges, contracted load, and PPAs table; data_package §4, Data-center contracts row].

Pricing is consequently layered. Energy sales can be spot-linked, fixed, indexed, hedged, or embedded in retail rates. Natural-gas input may be bought spot, forward, through transportation and storage arrangements, or passed through depending on contract terms. Gas-fired plants also earn capacity or resource-adequacy revenue where market design provides it, plus ancillary-service and congestion value. ERCOT has no centralized capacity market, so scarcity, ancillary services, bilateral contracting, and retail portfolio value matter more there. Geothermal output has baseload characteristics and can command clean or renewable attributes, while batteries arbitrage time, provide ancillary services, and help firm customer solutions.

The segment's go-to-market is therefore a three-way system: operate flexible and reliable assets; aggregate customers and load; then hedge the residual commodity exposure. Management said near-term open exposure was relatively limited and that the thermal base case was grounded in minimum historical gross margin and volume, which argues against valuing every uncontracted megawatt at a single forward curve [data_package §6, Q3 FY2025 Calpine hedges row; data_package §6, Q4 FY2025 Thermal base row]. It also means apparent revenue growth can be economically misleading. A higher gas price can increase reported revenue and purchased-fuel expense together, leaving RNF little changed, while a shift from wholesale net settlement to retail gross presentation can raise revenue without equivalent value creation.

Operationally, Calpine adds natural-gas, geothermal, storage, renewable, retail, and commercial capabilities to Constellation's roughly 55 GW combined fleet. The Geysers is unusually differentiated because it supplies around-the-clock renewable output from a location-specific steam resource. Capacity, ownership, and classification are kept on the verified package basis; no outside Calpine history is substituted [data_package §0a, Historical operating KPI series, Owned generation capacity row; data_package §1, reporting-structure paragraph; data_package §4, Calpine product/economic-unit row].

2. Current economics: 84-day Q1 FY2026 and reported TTM

The CEG-owned TTM contains only the acquisition-date-to-quarter-end contribution. During those 84 days, Calpine generated **$2.395 billion of segment revenue**, **$1.126 billion of RNF (Operating revenues net of Purchased power and fuel expenses)**, and a **47.0% RNF margin** [Q1 FY2026 Form 10-Q, Note 5, Calpine segment revenue and purchased-power/fuel table]. It supplied 28,586 GWh: 26,497 GWh from gas, oil, and renewables and 2,089 GWh of purchased power [Q1 FY2026 Form 10-Q, Calpine sources of electric supply; data_package §0a]. Revenue per supplied MWh was therefore about $83.78 and RNF per supplied MWh about $39.39 for this particular partial period. These are portfolio ratios, not realized generation prices: retail volumes, purchased power, hedges, capacity, ancillary services, and other commercial effects sit inside them.

The daily straight-line arithmetic is deliberately shown but not adopted as a forecast: $2.395 billion divided by 84 days and multiplied by 365 equals **$10.407 billion of revenue**, while $1.126 billion divided by 84 days and multiplied by 365 equals **$4.893 billion of RNF**. A mechanical annualization would ignore the six pre-close January days, summer and winter price/load peaks, plant outages, hedge rolls, capacity periods, the conditional 4.4 GW PJM divestiture, other required disposals, and the fact that retail and wholesale revenues can move differently. The model uses both figures only as transparent scale checks, applies case-specific normalization in the first forecast year, and then models organic and portfolio change separately. Purchase-accounting charges remain outside RNF and are not used to haircut or inflate this segment metric.

No product revenue split is disclosed. Gas generation, geothermal, storage, retail electricity, retail gas, and commercial optimization are real economic engines, but assigning any portion of the $2.395 billion to them would manufacture data. The finest decision-safe dollar line is the Calpine reportable segment as a whole [Q1 FY2026 Form 10-Q, Note 5; data_package §10, Calpine operating-region RNF split gap]. Customer-scale context is also combined-company rather than a Calpine-only revenue denominator: management cited approximately 275 million MWh of electricity and 800 Bcf of natural gas annually [Q1 FY2026 call, 2026-05-11, Shane Smith, CFO; data_package §6]. This appendix does not attribute those volumes wholly to Calpine.

Capital intensity is high even though RNF is defined before most operating and capital charges. Gas turbines require planned and unplanned maintenance, major inspections, emissions compliance, interconnection, fuel transportation, and working-capital or collateral support. Geothermal wells and steam-field infrastructure require reinjection and drilling to sustain output. Batteries have augmentation and degradation economics. Retail operations are asset-light in physical capital but can be heavy in credit, customer acquisition, billing technology, collateral, and risk controls. Those costs are not deducted in the segment RNF measure. This distinction is crucial: a 47% RNF margin is not comparable with a software gross margin or a statutory operating margin.

The acquisition also materially changed corporate leverage. At March 31, 2026, Constellation had $22.466 billion of gross debt and $21.666 billion of cash-only net debt after assuming roughly $12.6 billion of Calpine debt and repaying several corporate instruments [Q1 FY2026 Form 10-Q, consolidated balance sheet and debt footnote]. Management earmarked $3.4 billion for further deleveraging by the end of 2027 [Q4 FY2025 call, 2026-03-31, Shane Smith, CFO]. Debt and interest are not allocated to Calpine RNF here. They matter indirectly because a slower deleveraging path can constrain maintenance and growth investment, increase pressure to sell assets, and reduce the tolerance for merchant volatility.

3. Unit economics

3.1 From load and generation to RNF

For this segment, economic value is better understood as portfolio gross margin than as simple revenue growth. A useful conceptual bridge is:

- Owned generation earns energy, capacity where applicable, ancillary, congestion, renewable-attribute, and contract revenue.
- Retail and wholesale customer sales add gross revenue but require power and gas supply.
- Purchased power and fuel are deducted to arrive at RNF.
- Hedges re-time or stabilize the portfolio result, subject to accounting and settlement conventions.
- Operating and maintenance, depreciation, taxes other than income taxes, corporate costs, interest, and other bridge items are deducted later at the consolidated level and are not Calpine RNF expenses.

The first-order gas-plant driver is the clean spark spread: power price less gas price multiplied by heat rate, adjusted for variable operating costs, emissions, congestion, start costs, and availability. Efficient combined-cycle plants generally dispatch more often and can serve shaped retail load more economically. Peakers have lower utilization but valuable scarcity and ancillary-service optionality. A gas price increase is not automatically positive or negative. If power prices rise sufficiently or the portfolio is hedged, RNF can hold or improve; if fuel costs rise faster than power or retail rates, RNF compresses. Management's statement that Calpine was well hedged against weak ERCOT forwards supports near-term stability, not immunity after hedges roll [data_package §6, Q1 FY2026 ERCOT hedge row].

The second driver is the match between supply and load. Owned generation can naturally hedge retail demand, while retail load creates a route to market for generation. The benefit is imperfect because load shapes, nodes, weather, customer churn, and plant availability differ. A plant outage during a high-price retail obligation forces replacement purchases exactly when power is expensive. Conversely, excess generation during weak-price hours may be sold at unattractive margins. Risk management quality is therefore a real operating capability, not merely a financial overlay.

The third driver is contract tenure and structure. Long-term contracts reduce merchant exposure and collateral volatility and can support financing for incremental projects. They also cap upside, embed performance obligations, and create concentration risk. More than 10,000 MW of the combined fleet had executed long-term deals as of the 2026 outlook call, but the package does not disclose the Calpine-only portion or economics [data_package §0a, Hedges, contracted load, and PPAs table]. The model consequently does not assign a fabricated contracted percentage to Calpine.

3.2 Margin levers

The current 47.0% RNF margin can move up through higher capacity and ancillary revenue, stronger spark spreads, successful hedge rolls, high availability, favorable retail pricing, lower customer acquisition cost, improved supply-load matching, and higher-margin data-center or geothermal contracts. It can move down through gas basis dislocation, weak scarcity pricing, plant outages, renewable oversupply in midday hours, customer churn, credit loss, collateral stress, unfavorable hedge settlements, and divestiture of advantaged assets.

The planned PJM sale is a particularly important mix issue. Constellation agreed on March 18, 2026 to sell about 4.4 GW of gas capacity for $5 billion, subject to approvals and adjustments [Constellation/LS Power transaction announcement dated 2026-03-18; data_package §9]. The package does not disclose those assets' Calpine revenue or RNF. Subtracting an arbitrary revenue-per-MW would be false precision because capacity factors, contracts, heat rates, and market exposures differ. The base case instead embeds a moderate reduction in the normalized 2027 revenue base and holds the 2031 margin below the partial-quarter observation. The bear assumes sale timing and other remedy complexity disrupt optimization; the bull assumes portfolio simplification improves resilience without counting sale cash as segment revenue or RNF.

3.3 Reinvestment and cash conversion

RNF is upstream of the costs that keep these assets productive. A gas fleet can report stable RNF while needing heavy hot-gas-path maintenance. The Geysers can have attractive zero-fuel economics but still need steam-field management and capital. Battery revenue can grow while augmentation consumes cash. Retail can expand sales while increasing collateral and working capital. For that reason, management's promised at least $2 billion of annual incremental free cash flow is a separate test, not interchangeable with RNF [Q4 FY2025 call, 2026-03-31, Shane Smith, CFO; data_package §6].

Management also described $3.9 billion of growth projects targeting at least 10% unlevered returns. This is company-level deployment and cannot be allocated to Calpine without disclosure [Q4 FY2025 call, 2026-03-31, Shane Smith, CFO; data_package §6]. The bull case therefore requires execution evidence before treating development as margin accretive. The base includes measured growth from the operating fleet and disclosed commercial strategy, while the bear reflects capital rationing, project delay, or spending that earns less than planned.

4. Competitive dynamics

Calpine competes simultaneously in generation, retail, origination, and large-load solutions. The closest integrated merchant peers are Vistra and NRG. Vistra reported approximately 43.6 GW of capacity at year-end 2025, including 27.0 GW of natural gas, and roughly five million retail customers. It also agreed to acquire 5.5 GW of Cogentrix gas assets. That scale makes Vistra a direct rival for fuel, retail customers, hedges, acquisitions, capacity value, and data-center contracts [Vistra 2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1692819/000169281926000006/vistra-20251231.htm). NRG reported roughly 12 GW before its January 2026 LSP close, served about six million retail-energy customers, sold 154 TWh of electricity in 2025, and was developing new Texas gas capacity. It competes particularly strongly in ERCOT retail and

integrated supply [NRG 2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1013871/000101387126000004/nrg-20251231.htm).

Those peers demonstrate that generation scale alone is not a moat. Capital, trading systems, customer data, retail brands, fuel logistics, regulatory expertise, and a balanced fleet matter. Utilities and independent producers also compete in individual regions. New solar and storage can suppress daytime energy prices and reduce gas dispatch, while transmission can import cheaper power. Demand response and behind-the-meter solutions can substitute for peaking capacity. At the other extreme, load growth, retirement of coal plants, interconnection delays, and reliability needs increase the option value of existing dispatchable gas plants.

The market backdrop is favorable but not one-directional. EIA expected U.S. electricity load to grow 1.9% in 2026 and 2.5% in 2027, with ERCOT and PJM annual load growth averaging about 10% and 3%, respectively, between 2025 and 2027. Its high-demand scenario produced materially more gas generation, especially in ERCOT [EIA, fossil generation and data-center demand](https://www.eia.gov/todayinenergy/detail.php/detail.php?id=67344). Over the longer term, EIA's AEO 2026 cases put national electricity-consumption growth at 0.9%-1.6% annually and identify data centers as a major driver [EIA, Annual Energy Outlook 2026 narrative](https://www.eia.gov/outlooks/aeo/narrative/). These demand ranges support positive organic volume but do not justify using ERCOT's preliminary project queue as contracted load.

ERCOT itself warned that its preliminary 2032 forecast of approximately 367.8 GW was likely higher than expected actual future load growth because large-load requests were being added rapidly. The forecast is an indicator of opportunity and uncertainty, not a bankable sales plan [ERCOT preliminary 2026-2032 load forecast](https://www.ercot.com/news/release/04152026-ercot-releases-preliminary). This distinction is central to the cases. The bull assumes more requested load converts and Calpine wins profitable contracts. The base assumes only a fraction converts. The bear assumes interconnection, financing, or customer economics eliminate much of the queue while solar and storage additions pressure energy prices.

Pricing power varies by product. Existing efficient gas plants with transmission, fuel access, permits, and interconnections have growing replacement value because new projects face turbine lead times and siting constraints. They still sell into competitive markets and cannot set price continuously. Retail brands have some customer stickiness and cross-sell potential, but residential customers can switch and commercial customers bid contracts aggressively. Geothermal is more differentiated: around-the-clock renewable output is scarce, and the Geysers' steam resource, permits, operating knowledge, and interconnections are hard to replicate. Batteries are less differentiated technologically but benefit from site, interconnection, trading, and operating expertise.

PJM capacity economics add another layer. PJM's 2025 annual report noted that the 2026/2027 Base Residual Auction procured 134,376 MW and operated with an approximate $325/MW-day cap and $175/MW-day floor for the 2026/2027 and 2027/2028 auctions. Higher capacity prices can support dispatchable assets, but regulatory caps, auction redesign, transmission constraints, and asset divestitures limit extrapolation [PJM 2025 Annual Report, Markets](https://services.pjm.com/annualreport2025/markets/). ERCOT lacks an equivalent centralized capacity payment, so it exposes more value to scarcity, bilateral structures, and rule changes.

5. Moat at the segment level

Calpine has a moderate, portfolio-based moat rather than a franchise moat. Four assets are defensible. First, the fleet's existing sites, interconnections, permits, fuel access, and operating history would be slow and costly to duplicate. In a market with rising load and long equipment lead times, time-to-power matters. Second, the integrated generation-retail platform can internalize part of the supply-load hedge, originate structured products, and spread fixed risk systems over a large volume base. Third, the Geysers is genuinely scarce: baseload geothermal output is tied to a unique resource and specialized operating know-how. Fourth, Constellation's broader customer relationships and investment-grade ambitions can improve counterparty credibility for 15- or 20-year contracts [data_package §1, Calpine classification; data_package §4, Calpine product/economic-unit row].

The moat has limits. Commodity generation assets ultimately compete on location, efficiency, availability, contract position, and fuel. A competitor with a newer turbine, cheaper gas basis, or better node can out-earn Calpine. Retail customers are not captive. Hedges stabilize rather than create intrinsic spread. Contracting can convert a volatile asset into an annuity but may transfer upside to the customer. Regulatory agencies can force divestitures when market concentration becomes too high, as the current remedy package demonstrates. The acquisition itself therefore proves both the scale advantage and the antitrust ceiling.

Over five to ten years, the moat should persist if Calpine sustains high plant availability, retains commercial talent, integrates risk systems without control failures, maintains credit quality, and converts a sensible share of large-load interest into profitable contracts. It weakens if integration causes personnel loss, if debt pressure forces the sale of the best assets, if gas generation faces materially tighter environmental rules without compensation, or if solar-plus-storage and transmission reduce scarcity faster than load grows. The base case treats the moat as sufficient to preserve attractive RNF, not sufficient to guarantee expanding margins.

6. Historical growth rates reproduced from the data package

Calpine has no three-year CEG-owned revenue history. The table uses the required FY-3 to FY-1 display, but the pre-close cells explicitly retain the ownership boundary. No historical dollar is back-solved and no pre-acquisition Calpine revenue is introduced.

Product / sub-segment	FY-3 rev	FY-2 rev	FY-1 rev	3-yr CAGR	Most recent YoY	Data package cite
Calpine acquired thermal/geothermal/retail platform	FY2023 Not CEG-owned	FY2024 Not CEG-owned	FY2025 $0.000B ownership convention	N/M	N/M	[2025 Form 10-K, Note 5; Q1 FY2026 Form 10-Q, Note 5]
Gas generation	Not separately disclosed	Not separately disclosed	Not separately disclosed	N/M	N/M	[data_package §4, Calpine product/economic-unit row]
Geothermal, storage, and solar	Not separately disclosed	Not separately disclosed	Not separately disclosed	N/M	N/M	[data_package §4, Calpine product/economic-unit row]
Retail electricity, retail gas, and commercial optimization	Not separately disclosed	Not separately disclosed	Not separately disclosed	N/M	N/M	[data_package §4, Retail/customer solutions row]

The first CEG-owned observation is shown separately because calling it FY2025 history or inserting it into an annual CAGR would be misleading.

Current disclosed line	Period	Revenue	RNF (Operating revenues net of Purchased power and fuel expenses)	RNF margin	Volume	Data package cite
Calpine reportable segment	Jan. 7-Mar. 31, 2026; 84 days	$2.395B	$1.126B	47.0%	28,586 GWh supplied/sold	[Q1 FY2026 Form 10-Q, Note 5 and sources-of-electric-supply table]

Arithmetic check: no annual YoY tie-out exists because there are not two CEG-owned annual observations. The valid current-period checks are $2.395B × 47.0% = $1.126B after rounding, and 26,497 GWh owned output + 2,089 GWh purchased power = 28,586 GWh total supply. The daily straight-line checks are $2.395B ÷ 84 × 365 = $10.407B revenue and $1.126B ÷ 84 × 365 = $4.893B RNF; both are scale diagnostics rather than forecasts.

7. Management guidance quoted from data package Section 6

- **Q2 FY2025, 2025-08-07, Joe Dominguez, CEO, Calpine value:** “Calpine will add $2 in EPS and $2 billion of free cash flow before growth starting next year.” [data_package §6, Q2 FY2025 Calpine value row]. This was the initial acquisition case. EPS and FCF are consolidated outputs, not Calpine revenue or RNF guidance, so they are used only as cross-checks.

- **Q2 FY2025, 2025-08-07, Joe Dominguez, contract strategy:** “long-term contracts like our Meta and Microsoft deals” are becoming “an ordinary part of our strategy” [data_package §6, Q2 FY2025 Contract strategy row]. The implication is a gradual shift from open merchant exposure toward longer-duration customer arrangements, but the mix and prices are undisclosed.

- **Q3 FY2025, 2025-11-07, Dan Eggers, CFO, Calpine hedges:** “near-term open exposure is relatively limited” [data_package §6, Q3 FY2025 Calpine hedges row]. This supports a less volatile near-term RNF path than a spot-only mark, while outer years remain exposed as hedges roll.

- **Q4 FY2025, 2026-03-31, Joe Dominguez, contracted fleet:** “executed deals for over 10,000 megawatts of our fleet” [data_package §6, Q4 FY2025 Contracted fleet row]. The figure is combined-company, so this model does not assign all 10,000 MW to Calpine or infer contract revenue.

- **Q4 FY2025, 2026-03-31, Shane Smith, CFO, FCF accretion:** “at least $2 billion of annual incremental free cash flow” [data_package §6, Q4 FY2025 FCF accretion row]. This is the main acquisition cash-conversion benchmark. RNF can meet this appendix's forecast while the acquisition still disappoints if maintenance capex, interest, tax, or working capital absorb too much cash.

- **Q4 FY2025, 2026-03-31, Shane Smith, growth capex:** “$3.9 billion in growth projects” with “returns of at least 10% on an unlevered basis” [data_package §6, Q4 FY2025 Growth capex row]. This supports selected development, but it is not Calpine-only and the model does not credit the full amount as segment revenue.

- **Q4 FY2025, 2026-03-31, Shane Smith, deleveraging:** “earmarked $3.4 billion to delever the Calpine debt stack” [data_package §6, Q4 FY2025 Deleveraging row]. Successful execution protects investment-grade metrics and reduces pressure for forced sales; it does not change RNF directly.

- **Q4 FY2025, 2026-03-31, Shane Smith, thermal base:** “minimum expected gross margin and volume grounded in historical experience” [data_package §6, Q4 FY2025 Thermal base row]. The base case follows that conservative framing rather than fully repricing the fleet to favorable spot conditions.

- **Q1 FY2026, 2026-05-11, Joe Dominguez, near-term FCF:** “the '26, '27 period producing a forecasted $8.4 billion” [data_package §6, Q1 FY2026 FCF outlook row]. This is combined FCF before growth over two years, not a Calpine segment target.

- **Q1 FY2026, 2026-05-11, Joe Dominguez, longer FCF:** “the '28-'29 period rising to $11.5 billion to $13 billion” [data_package §6, Q1 FY2026 Longer FCF row]. This provides a later consolidated cash-flow reasonableness band; optional projects and segment RNF still need independent underwriting.

- **Q1 FY2026, 2026-05-11, Andrew Novotny, Calpine CEO, ERCOT hedge:** “we've been well hedged and protected against it” [data_package §6, Q1 FY2026 ERCOT hedge row]. Near-term weak forwards should not be translated immediately into an RNF collapse, but hedge protection is finite.

- **Q1 FY2026, 2026-05-11, Shane Smith, CFO, customer scale:** “approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually” [data_package §6, Q1 FY2026 Customer scale row]. This describes the commercial denominator available for cross-sell and supply optimization, but it is not a Calpine-only volume guide.

There is **[DATA GAP: no Calpine-specific FY2026 revenue, RNF, regional revenue, regional RNF, generation-product revenue, retail revenue, or organic-growth guide]**. Scenario design must therefore start from the actual 84-day observation and visibly separate ownership normalization from organic growth.

8. Forward growth assumptions

Method: reported-ownership growth versus normalized organic growth

The TTM anchor is $2.395 billion because that is the only CEG-owned Calpine revenue in the twelve months ended March 31, 2026. The first forecast year replaces three missing pre-ownership quarters with a full year and incorporates seasonality, hedge roll, and remedy sales. Consequently, the five-year reported CAGR appears very high even when the underlying business grows modestly. The model presents both numbers to avoid calling acquisition timing organic growth.

The base case reaches $9.5 billion in the year ending March 31, 2027, 8.7% below the $10.407 billion daily straight-line revenue diagnostic. That haircut recognizes asset-sale/remedy effects, seasonal mix, and the absence of evidence that the acquisition-period daily rate persists. Revenue then compounds at 3.5% from the normalized 2027 base to $10.9 billion in 2031. The bear normalizes to $8.6 billion, falls as remedy sales and weak merchant conditions bite, then recovers to $8.5

billion. The bull reaches $10.2 billion in 2027 and compounds 6.3% thereafter to $13.0 billion as more large-load demand converts, contracts expand, and high availability monetizes scarcity. These revised paths deliberately reject the prior $12.0 billion base and $14.0 billion bull endpoints: with only one 84-day observation, the package does not support both a near-full run-rate normalization and the former high organic growth assumptions.

Base case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Base CAGR TTM→TTM+5y	Justification (1-2 sentences)
Calpine reportable segment; single disclosed dollar line	N/M; new ownership	N/M; first 84-day observation	No segment revenue guide	35.4% reported; 3.5% normalized 2027-2031	The reported CAGR is dominated by adding three missing ownership quarters. The normalized rate is above EIA's 0.9%-1.6% long-run national demand range but below raw ERCOT/PJM queue growth; it requires selective contract wins while recognizing remedy sales and competitive bidding.

The base case assumes the portfolio captures load growth through dispatch, retail sales, and contracts while competitive bidding, renewables, and remedy sales limit monetization. Management's minimum-gross-margin framing and limited near-term open exposure support stability. No Calpine product mix is fabricated.

Bull case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bull CAGR TTM→TTM+5y	Justification (1-2 sentences)
Calpine reportable segment; single disclosed dollar line	N/M; new ownership	N/M; first 84-day observation	No segment revenue guide	40.3% reported; 6.3% normalized 2027-2031	A first full year starts modestly below the acquisition-period daily rate. CyrusOne phases, additional profitable contracts, retail cross-sell, favorable scarcity, and strong availability then drive above-market growth, but the model does not assume the full ERCOT request queue converts.

The bull requires successful CyrusOne development, additional profitable long-term contracts, sustained gas-plant reliability, and enough fuel/interconnection access to serve new load. It also assumes remedy sales remove less economic value than their nameplate capacity suggests. It does not add the $5 billion sale proceeds to revenue or RNF.

Bear case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bear CAGR TTM→TTM+5y	Justification (1-2 sentences)
Calpine reportable segment; single disclosed dollar line	N/M; new ownership	N/M; first 84-day observation	No segment revenue guide	28.8% reported; (0.3%) normalized 2027-2031	The portfolio normalizes well below the daily run-rate, then remedy sales, renewable price pressure, lost retail load, and weak hedge rolls outweigh load growth before a partial recovery. Higher gas prices without full power-price or retail pass-through constrain reported revenue quality.

The bear is not a perpetual-collapse case. Existing assets, contracts, and growing system load still provide a floor. It instead assumes the transaction's most attractive opportunities take longer, customer queues are overstated, and debt/integration pressure reduces strategic flexibility.

Year-by-year ownership normalization and growth path

Case / metric	TTM 3/31/26 actual	3/31/27	3/31/28	3/31/29	3/31/30	3/31/31	2027-2031 normalized CAGR
Bear revenue	$2.395B	$8.600B	$8.350B	$8.200B	$8.300B	$8.500B	(0.3%)
Bear RNF margin	47.0%	38.0%	36.0%	34.5%	34.5%	35.0%	N/M

Case / metric	TTM 3/31/26 actual	3/31/27	3/31/28	3/31/29	3/31/30	3/31/31	2027-2031 normalized CAGR
Bear RNF	$1.126B	$3.268B	$3.006B	$2.829B	$2.864B	$2.975B	(2.3%)
Base revenue	$2.395B	$9.500B	$9.800B	$10.200B	$10.600B	$10.900B	3.5%
Base RNF margin	47.0%	43.0%	42.5%	42.0%	42.0%	42.0%	N/M
Base RNF	$1.126B	$4.085B	$4.165B	$4.284B	$4.452B	$4.578B	2.9%
Bull revenue	$2.395B	$10.200B	$10.800B	$11.500B	$12.300B	$13.000B	6.3%
Bull RNF margin	47.0%	47.0%	47.5%	48.0%	48.0%	48.0%	N/M
Bull RNF	$1.126B	$4.794B	$5.130B	$5.520B	$5.904B	$6.240B	6.8%

The 2027 step is acquisition normalization, not a claim that customer demand grows 259%-326%. Subsequent paths are the decision-relevant organic and portfolio assumptions. The RNF rows are revenue multiplied by the case margin in each year; no corporate, interest, purchase-accounting, O&M, depreciation, tax, or unallocated bridge item is embedded. There is no precedent-based product deceleration comparison because no Calpine product-level dollar growth history exists; using a peer's consolidated growth rate would create false comparability across hedge books and revenue presentation.

9. Forward RNF (Operating revenues net of Purchased power and fuel expenses) margin assumptions

The current segment margin is 47.0% for the 84-day acquisition-period observation [Q1 FY2026 Form 10-Q, Note 5, Calpine segment table]. The base moves to 42.0% by 2031, the bear to 35.0%, and the bull to 48.0%. The bear and base moves exceed 100 basis points; the bull is capped only 100 basis points above the observed partial-period margin because the package provides no Calpine annual margin history. These are explicitly scenario sensitivities, not management guidance.

Case	Current RNF margin	3/31/27	3/31/28	3/31/29	3/31/30	TTM+5 RNF margin	Mechanism
Bear	47.0%	38.0%	36.0%	34.5%	34.5%	35.0%	Advantaged-asset divestiture, weaker hedge rolls, gas/basis pressure, retail churn, outages, and renewable oversupply reduce portfolio gross margin by 1,200 bps versus the 84-day observation; later load growth stabilizes it.
Base	47.0%	43.0%	42.5%	42.0%	42.0%	42.0%	A 500-bps normalization haircut absorbs uncertain seasonality and remedy dilution; contracting, supply-load matching, disciplined hedging, and availability prevent a larger decline.
Bull	47.0%	47.0%	47.5%	48.0%	48.0%	48.0%	Scarcity, capacity/ancillary value, high availability, favorable long-term contracts, and geothermal/data-center mix add only 100 bps versus Q1, avoiding an unsupported 50% terminal margin.

The base's 500-basis-point decline recognizes that one quarter can have unusually favorable seasonal, hedge, or mix effects and that required sales remove assets without a disclosed margin profile. It does not allocate O&M, depreciation, interest, taxes, purchase-accounting, unallocated activity, or integration charges to RNF. The bear's 1,200-basis-point decline is driven by gross-margin mechanisms only. The bull's 100-basis-point expansion requires durable commercial improvement and is not an accounting reclassification.

Product-level margins are not calculated because neither product revenue nor product RNF is disclosed. A revenue-weighted average of invented gas, geothermal, storage, and retail margins would look precise but would not be reconstructable from

the verified package. The single disclosed Calpine line is therefore the only decision-safe bottom-up unit.

10. Segment rollup

TTM+5 revenue and RNF (Operating revenues net of Purchased power and fuel expenses)

Case	Product line	TTM+5 revenue	RNF margin	TTM+5 RNF	Reconciliation
Bear	Calpine reportable segment; single disclosed dollar line	$8.500B	35.0%	$2.975B	$8.500B × 35.0% = $2.975B
Base	Calpine reportable segment; single disclosed dollar line	$10.900B	42.0%	$4.578B	$10.900B × 42.0% = $4.578B
Bull	Calpine reportable segment; single disclosed dollar line	$13.000B	48.0%	$6.240B	$13.000B × 48.0% = $6.240B

Because Calpine is the only disclosed additive line, product revenue sums exactly to the segment total and the revenue-weighted segment margin equals the line margin. This is not an analytical shortcut; it is compliance with the issuer's disclosure boundary. A later filing that supplies Calpine East/West/Texas/Retail revenue and RNF would trigger a model refinement.

The probability-weighted endpoint is **$10.495 billion of revenue and $4.346 billion of RNF**, using 30% bear, 55% base, and 15% bull probabilities. The arithmetic is `30% × $8.500B + 55% × $10.900B + 15% × $13.000B = $10.495B` revenue and `30% × $2.975B + 55% × $4.578B + 15% × $6.240B = $4.346B` RNF. The implied probability-weighted RNF margin is 41.4%, calculated as weighted RNF divided by weighted revenue, not as an average of the three margins. A 30% bear weight reflects the unseasoned 84-day history and mandatory-remedy uncertainty; a 55% base weight reflects management's hedged/minimum-gross-margin framing; and a 15% bull weight recognizes that the upside requires several undisclosed-price contracts and sustained scarcity to succeed concurrently. This weighted result is a scenario statistic, not a fourth case. It remains on the sealed RNF basis and must flow through the separately modeled statutory bridge before any conclusion about operating income, net income, or EPS.

Deal and balance-sheet cross-check

The segment model does not allocate corporate financing costs, but the acquisition thesis is inseparable from cash conversion. The base segment RNF of $4.578 billion in 2031 needs to fund its share of fleet maintenance and corporate expenses before contributing to the promised cash flow. The $3.4 billion deleveraging target through 2027 improves resilience only if announced asset-sale proceeds close and are not simultaneously counted as buyback or growth cash. In the bear, delayed sales and weaker RNF increase interest and collateral pressure at the consolidated level. In the bull, faster deleveraging reduces financing risk, but it still does not increase Calpine RNF mechanically.

Integration risk also sits partly outside RNF. Consolidating dispatch, retail billing, credit, fuel, trading, outage, and hedge systems can create customer or control failures even if plants operate well. Retaining Calpine's commercial talent is particularly important because hedge books and customer obligations contain institutional knowledge. The base assumes orderly integration; the bear assumes disruption and conservative risk limits reduce optimization; the bull assumes scale improves origination without taking materially more open commodity risk.

11. Key risks and wildcards

- **Merchant power and gas basis [Bear]:** Hedge protection rolls off. A mismatch between gas, power, congestion, and retail prices can compress RNF even when reported revenue rises. ERCOT's energy-only structure amplifies both upside and downside.

- **Retail load and customer churn [Bear/Base]:** Competitive retail can stabilize generation economics, but fixed-price obligations become costly when replacement power spikes. Customer attrition, bad debt, and acquisition spending can erode value even though some costs sit below RNF.

- **Data-center conversion [Bull/Base/Bear]:** The CyrusOne agreement provides a concrete 380 MW phase and an exclusive second phase, but timing, interconnection, conditions, customer buildout, and confidential pricing matter. The bull wins additional economic contracts; the bear sees queues shrink or terms transfer most value to customers [data_package §0a, Hedges, contracted load, and PPAs table].

- **Asset-sale execution [Bear/Base]:** The 4.4 GW PJM transaction is conditional and subject to adjustments. Delay prolongs leverage; closure may remove valuable RNF. Neither outcome can be quantified precisely without asset-level revenue and margin disclosure [data_package §9, March 18, 2026 corporate action].

- **Integration and controls [Bear]:** Combining trading, credit, outage, retail, and billing systems can create operational errors, hedge gaps, talent loss, or customer disruption. A failure may appear first in unallocated or statutory-bridge items rather than Calpine RNF.

- **Deleveraging and collateral [Bear]:** A slower $3.4 billion deleveraging program raises interest and limits investment [Q4 FY2025 call, 2026-03-31, Shane Smith, CFO]. The Q1 filing estimated roughly $3.0 billion of additional collateral could be required after a below-investment-grade downgrade [Q1 FY2026 Form 10-Q, liquidity and credit-support disclosure]. This is a corporate liquidity risk, not an RNF expense.

- **Plant availability and extreme weather [Bear/Bull]:** Outages during scarcity can force expensive replacement purchases and destroy retail hedge value. High availability during scarcity can create outsized RNF. Q1's combined fleet EFOF was 4.5%, but a single quarter is not a durability proof [data_package §0a, Historical operating KPI series and Last-four-quarter operations].

- **Renewable and storage competition [Bear/Base]:** Solar growth depresses midday energy prices and storage competes for ancillary value. Gas remains valuable for ramps and longer-duration reliability, but annual utilization may not match load growth.

- **Environmental and permitting policy [Bear]:** Tighter greenhouse-gas, air, water, or carbon rules can require capex, limit dispatch, or shorten lives. Conversely, a policy regime that values firm reliability or carbon capture can improve asset value.

- **Geothermal durability [Base/Bull]:** The Geysers' scarce baseload renewable output is a moat, but steam-field productivity, reinjection infrastructure, seismic/permitting issues, and development execution remain physical constraints. Upside comes from expansion or premium contracts, not an assumed infinite resource.

- **Fuel and infrastructure [Bear/Bull]:** EIA's 2026 outlook expected natural-gas production to grow, but also identified pipeline buildout needs. Adequate gas supply supports dispatch; local transportation constraints can widen basis and impair reliability [EIA, Annual Energy Outlook 2026 release](https://www.eia.gov/pressroom/releases/press587.php).

- **Competition [Bear/Base]:** Vistra and NRG have scaled integrated generation-retail portfolios and are adding gas capacity. Competition can bid away large-load economics and increase customer-acquisition costs even in a growing market.

- **Accounting and taxonomy [All cases]:** Q1 consolidated acquired revenue of $3.136 billion exceeded the $2.395 billion Calpine segment assignment because some activity was classified as unallocated. A future taxonomy change could move economics between Calpine and unallocated RNF without changing the company total [Q1 FY2026 Form 10-Q, acquisition revenue disclosure and Note 5 segment table; data_package §3]. The model must be restated rather than treating reclassification as growth.

Summary

Case	Segment TTM+5 Revenue	Exact profit metric	Segment TTM+5 Profit Margin	Segment TTM+5 Profit	Probability
Bear	$8.500B	RNF (Operating revenues net of Purchased power and fuel expenses)	35.0%	$2.975B	30%
Base	$10.900B	RNF (Operating revenues net of Purchased power and fuel expenses)	42.0%	$4.578B	55%

Case	Segment TTM+5 Revenue	Exact profit metric	Segment TTM+5 Profit Margin	Segment TTM+5 Profit	Probability
Bull	$13.000B	RNF (Operating revenues net of Purchased power and fuel expenses)	48.0%	$6.240B	15%

The central underwriting conclusion is that Calpine can be a valuable growth and diversification engine, but its first disclosed quarter is not enough to prove normalized earnings power. The base case earns its result through a transparent full-year ownership normalization followed by 3.5% normalized organic/portfolio revenue growth and a 42.0% RNF margin. Its $4.578 billion terminal RNF remains 6.4% below the unseasoned $4.893 billion daily annualization of the 84-day observation; the bull reaches $6.240 billion only through 6.3% normalized revenue growth and a 48.0% margin, while the bear falls to $2.975 billion through remedy/merchant pressure and a 35.0% margin. The major swing factors are not nameplate capacity alone: they are which assets remain after remedies, how hedges roll, whether retail load and generation stay matched, how much large-load interest becomes binding and profitable, and whether the combined company deleverages without starving the fleet of maintenance and growth capital.

Appendix B5 - New York

New York — Segment Deep Dive

Company: Constellation Energy Corporation (CEG) **Run:** pulse-cio-20260806T090230+0800 **Information cutoff:** 2026-08-06 09:02:30 SGT **Forecast anchor:** TTM ended 2026-03-31 **Forecast horizon:** 2031-03-31, exactly five calendar years **Exact profit basis:** RNF (Operating revenues net of Purchased power and fuel expenses) **Reporting scale:** USD billions unless stated otherwise

0. Segment boundary and taxonomy note

The New York segment is the issuer's NYISO regional generation and customer portfolio. Its reporting boundary was stable through FY2025 and remains a legacy reportable segment after Calpine became a sixth segment on January 7, 2026. There was no New York restatement within the last three years. Official Note 5 figures control: the live FMP product endpoint misclassified $199 million of FY2025 revenue and showed $2.389 billion, while the verified official figure is $2.190 billion [data_package §0a, Classification paragraph; §1, taxonomy note]. This appendix therefore uses only the official series preserved in data_package.md and the QFR-sealed bridge. It does not use the FMP product row, does not re-fetch CEG historicals or management quotations, and does not allocate corporate or statutory-bridge adjustments into New York.

1. What this segment actually is

New York is best understood as a regional gross-margin portfolio rather than as a conventional product company. CEG combines the economics of owned nuclear generation in New York, NYISO energy and capacity market participation, environmental and reliability attributes, hedging, and customer-facing load activity. The customer proposition is reliable electricity and related energy solutions; the asset proposition is a large block of high-capacity-factor, low-variable-cost nuclear supply. Segment revenue records the top line from that portfolio. Purchased power and fuel are then deducted to arrive at RNF, the issuer's exact segment performance measure.

The physical core consists of the Ginna, FitzPatrick, and Nine Mile Point plants. CEG's June 2026 license-renewal announcement describes 576 MW at Ginna, 842 MW at FitzPatrick, and 1,907 MW across Nine Mile Point's two units. CEG owns all of Nine Mile Point Unit 1 and 82% of Unit 2; LIPA owns the remaining 18% of Unit 2. These are gross plant ratings, not a substitute for the segment's verified financial history and not an additive revenue build. They establish why New York's economics are dominated by baseload nuclear availability and policy support rather than gas fuel spreads. [Constellation's June 26, 2026 license-renewal announcement](https://www.constellationenergy.com/news/2026/06/constellation-seeks-license-renewals-for-two-new-york-units-through-2049.html) provides the current plant roster and ownership context.

The go-to-market model has four overlapping channels. First, physical generation clears into NYISO's energy and ancillary-services markets. Second, qualified capacity is sold through NYISO's installed-capacity construct, principally Rest-of-State for the upstate plants. Third, nuclear output earns policy-linked value from New York's Zero-Emissions Credit program and the federal nuclear production tax credit. Fourth, CEG's commercial organization hedges and sells load, shaping realized revenue and purchased-power expense. These channels are economically linked. A higher market price can lift energy receipts while reducing some support payments; a customer book can stabilize gross margin but requires purchased power when owned output and load do not match by hour, location, or volume.

The segment is therefore not a simple MWh × spot price business. The data package explicitly warns that NYISO reference prices are not CEG realized prices. RNF already captures generation, retail/load, hedges, ZEC and PTC support, capacity, purchased power, and fuel. The forecast uses RNF as the economic output and applies market evidence only to the direction and durability of revenue and margin. It does not pretend that a day-ahead reference price is the realized merchant price.

2. Current economics

TTM revenue was $2.197 billion and TTM RNF was $1.608 billion, producing a 73.2% RNF margin [data_package §3, New York table, TTM column; TTM_NORMALIZED_RECONCILIATION]. FY2025 revenue was $2.190 billion, up 6.8%, while FY2025 RNF was $1.600 billion and the RNF margin was 73.1% [data_package §3, New York table, FY2025 column and YoY row; 2025 Form 10-K Note 5]. These figures are remarkably close to the TTM anchor because Q1 FY2026 revenue of $0.569 billion replaced Q1 FY2025 revenue of approximately $0.562 billion, while Q1 RNF of $0.409 billion replaced approximately $0.401 billion [data_package §5; Q1 FY2026 Form 10-Q Note 5; FY2025 Form 10-K Note 5]. The verified last-four-quarter

sequence was $0.535 billion, $0.558 billion, $0.535 billion, and $0.569 billion of revenue, with RNF margins of 74.2%, 71.5%, 75.3%, and 71.9% [data_package §5, New York Q2 FY2025 through Q1 FY2026 rows; Q2 and Q3 FY2025 Forms 10-Q Note 5; FY2025 less nine months; Q1 FY2026 Form 10-Q Note 5].

The current economics show three important features. First, quarterly top-line growth slowed to 1.2% in Q1 FY2026 even though the full-year FY2025 comparison was 6.8%. Second, RNF margin remained above 71% in every quarter, a sign that purchased power and fuel did not absorb the majority of revenue even when seasonal mix moved. Third, historical revenue and RNF do not move in lockstep: FY2023-FY2025 revenue grew from $2.021 billion to $2.190 billion, while RNF rose from $1.251 billion to $1.600 billion and margin expanded from 61.9% to 73.1% [data_package §3, New York table]. That divergence is precisely why revenue growth alone is a poor proxy for segment value.

Capital intensity is real but is not disclosed by segment. Nuclear plants require refueling outages, preventive maintenance, aging-management investment, security, regulatory compliance, and eventually license-renewal capital. CEG does not provide New York-only capex or maintenance-versus-growth capex. `[DATA GAP: New York-specific capex, maintenance expense, and invested-capital history are not disclosed in data_package §§3-4.]` At consolidated level, FY2025 capex was $2.949 billion, or 11.5% of revenue, but allocating that amount to New York would violate the bridge and create false precision [data_package §7, FY2025 row]. The correct model holds New York's RNF at the segment level and leaves operating and maintenance, depreciation, taxes other than income tax, and corporate/unallocated items to the synthesis bridge.

CEG does not disclose a dollar product split within New York. The finest verified unit is `Regional generation and customer portfolio — NYIS0`; standalone nuclear revenue, capacity revenue, ZEC/PTC receipts, retail revenue, customer volumes, and ancillary-service revenue are not separately disclosed [data_package §4, New York row and disclosure note]. `[DATA GAP: no New York product-dollar, realized-price, hedge-volume, retail-load, or contract-price split is disclosed.]` Consequently, a one-line financial forecast is more faithful than invented sub-products. The appendix still models the underlying drivers explicitly in prose and in the margin framework.

3. Unit economics

The cleanest unit-economics identity is:

`New York segment revenue − purchased power and fuel = New York RNF`.

At the TTM anchor, purchased power and fuel implied by that identity were $0.589 billion, or 26.8% of revenue. This is a mechanical subtraction of the two verified data-package values, not a separately disclosed expense line for New York. RNF of $1.608 billion is the amount available before the independently reported corporate/unallocated and statutory operating-expense bridge. It must not be called operating income, EBITDA, or contribution after operating expenses.

The generation side has low short-run fuel cost relative to gas-fired power, but very high fixed cost and outage sensitivity. When the nuclear units operate, incremental MWh can convert strongly to RNF because nuclear fuel expense is comparatively small and the fleet can monetize energy, capacity, ancillary, ZEC, and PTC value. When a unit is offline, lost output is not merely lost revenue: the customer and hedge book may require replacement power, and refueling or forced-outage work raises costs elsewhere in the statutory bridge. RNF margin can therefore fall through both the numerator and denominator.

The customer side adds a different set of economics. A load-serving or retail position may carry a lower accounting RNF margin than owned generation because purchased power is explicit, yet it can reduce absolute volatility when customer prices and supply are hedged coherently. CEG's broader commercial scale is substantial, but the data package gives only combined-company customer volume after Calpine and does not assign it to New York. This appendix does not treat the combined 275 million MWh electricity figure as a New York KPI [data_package §6, Q1 FY2026 customer-scale row].

Hedging changes timing rather than eliminating risk. CEG historically used a three-year ratable sales plan, with an approximate 90% / 60% / 30% pattern, and the verified FY2022 year-end New York coverage benchmark was included with other legacy regions [data_package §0a, Hedges table]. The outer years remain open by design. A rising-price environment therefore feeds into RNF gradually; a falling-price environment also rolls into results gradually. The federal nuclear PTC adds a second dampener because the credit declines as facility gross receipts rise. New York's ZEC formula adds a third because ZEC payments are reduced when modeled market energy and capacity receipts exceed the formula threshold and are further coordinated with federal support.

The state policy mechanics are especially important at the five-year horizon. The New York Public Service Commission extended ZEC support from the March 2029 end of ZEC 1.0 through 2049. The adopted ZEC 2.0 schedule uses a nine-month bridge tranche in 2029 and two-year tranches thereafter. For 2030-2031, the order lists a maximum ZEC price of $39.01/MWh and estimated combined market-plus-ZEC revenue of $72.01/MWh under the order's stated assumptions. Market energy and capacity revenue above $39/MWh reduces the ZEC price commensurately. The program also nets or adjusts for federal nuclear PTC value. Those figures are policy formula inputs, not a guaranteed realized price for CEG, but they materially reduce the probability of an uneconomic collapse in New York RNF by 2031. [The January 22, 2026 PSC order](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0012E79B-0000-CA56-B121-646E90864AF9%7D) contains the tranche schedule and offset mechanics on PDF pages 48 and 62-64.

There is also a performance condition. The PSC retained the combined annual ZEC cap of 27,618,000 MWh for FitzPatrick, Ginna, and Nine Mile Point. If the group produces below 85% of its tranche-period cap, the next tranche's cap is reduced by 1,000,000 MWh until performance recovers. This makes availability economically valuable twice: output earns market revenue and protects future policy-supported volume. It also prevents the model from treating ZEC as an unconditional annuity. The base case assumes ordinary high nuclear availability, the bear case prices a material but not permanent performance setback, and the bull case requires both availability and attractive contract or market realization.

4. Competitive dynamics

New York's competitive set is broader than other nuclear operators. In energy, the segment competes with gas, hydro, imports, renewables, storage, and demand flexibility. In capacity, it competes with any resource accredited to meet NYISO reliability needs. In zero-emission policy, existing nuclear competes for ratepayer support and political legitimacy with renewables, transmission, storage, demand management, and new nuclear. In customer supply, it competes with utilities, retail energy providers, independent generators, and integrated commodity marketers.

Nuclear's central advantage is firm, high-output, low-carbon supply. The four reactors provided about 21% of New York's electricity and more than 40% of the state's zero-emission power according to the PSC. The Commission concluded that losing them would create unacceptable reliability risk, raise emissions, and increase transition costs. That judgment directly underpins the ZEC extension and is stronger evidence of policy relevance than a generic claim that nuclear is `clean`. [The PSC's January 22, 2026 announcement](https://dps.ny.gov/news/commission-announces-extension-nuclear-power-credit-program) describes the fleet share, reliability finding, and safeguards.

The competitive weakness is that upstate nuclear is not fully exposed to the highest-priced downstate zones, and capacity-market geography can blunt scarcity signals. The NYISO Market Monitoring Unit reported that 2025 real-time energy prices ranged from $54.40/MWh in the West to $81/MWh on Long Island, reflecting fuel and transmission constraints. It also reported 2025-2026 capability-year capacity prices of $51/kW-year outside New York City, up 38%, versus $132/kW-year in New York City. New York's plants are upstate and primarily receive Rest-of-State capacity economics, not the NYC locality price. [The NYISO MMU's 2025 State of the Market report](https://www.potomaceconomics.com/wp-content/uploads/2026/05/NYISO-2025-SOM-Report__5-19-2026-final.pdf), executive-summary pages i-vii, supplies these market observations.

The same report shows why scarcity can persist. Retirements outpaced new entry, 1.2 GW of conventional generators filed retirement notices in the prior year, and state clean-resource deployment lagged expectations. CHPE adds supply, but NYISO's planning analysis showed deficient margins in 2030 under its conservative planning case. The signal is not uniformly bullish for New York RNF: more imports, storage, solar, and transmission can suppress upstate energy prices, while system scarcity and winter fuel limitations increase the reliability value of always-on nuclear. The net effect is a more valuable firm asset but a potentially flatter captured energy price during renewable-heavy hours.

Large-load growth is another two-sided driver. NYISO's 2025 Gold Book baseline forecast increases state energy consumption from 152,400 GWh in 2025 to 165,640 GWh in 2031, a 1.4% annualized 2025-2030 pace and continued growth into 2031. The large-load forecast rises from 3,710 GWh in 2025 to 16,380 GWh in 2031 and from 466 MW to 2,173 MW of summer peak impact. Zone C, where Nine Mile Point and FitzPatrick sit, is the largest incremental upstate line: large-load energy rises from zero in 2025 to 5,380 GWh by 2031. These are system forecasts, not CEG contracts. They support the probability of stronger local energy demand and contract opportunities but cannot be inserted directly into CEG revenue. [NYISO's 2025 Gold Book](https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf), Tables I-1a and I-14 on report pages 17 and 58-59, is the source.

Pricing power is therefore institutional rather than unilateral. CEG cannot name a spot market price. It has influence through scarce generation, a large customer platform, hedge sophistication, and the option to negotiate long-duration clean-energy contracts, but the market and regulators set important parts of the revenue stack. The ZEC formula itself takes away some upside as market receipts rise. The PTC does the same. This lowers downside variance but also means a simple bull case that adds market upside, full PTC, and full ZEC would double-count the same economic protection.

5. Moat at the segment level

The segment has a meaningful moat, but it is an asset-and-policy moat rather than a classic brand moat. The physical barrier is enormous: replicating roughly 3.3 GW of operating nuclear capacity with interconnection rights, trained labor, licenses, security systems, spent-fuel infrastructure, and local operating history would take many years and billions of dollars. The regulatory barrier is equally important. Existing plants have established NRC licenses and NYISO market positions. New nuclear development may eventually add supply, but it will not erase the installed fleet's value within the 2031 horizon.

The moat's second layer is reliability. NYISO projects rising energy demand, declining planning margins under stressed assumptions, and increasing winter risk as gas availability becomes constrained. Nuclear's fuel security and around-the-clock output are difficult for short-duration storage or weather-dependent generation to replicate. The MMU noted that winter adequacy risk represented 14.8% of total reliability risk in the 2026-2027 IRM study and advocated separate seasonal capacity products. If market design better recognizes winter dependability, nuclear's capacity value could improve.

The third layer is policy durability. ZEC 2.0 runs to 2049, uses formulaic tranches, includes performance conditions, and coordinates with federal credits. It is not merely a press release; it is an adopted PSC order with implementation and review mechanics. The state has an explicit interest in avoiding the emissions, reliability, and cost consequences of retirement. That creates a strong floor around continued operation, though not a guarantee of any particular CEG RNF margin.

The moat is not invulnerable. Three reactors have license dates that matter. Nine Mile Point Unit 1 and Ginna needed subsequent license renewal to operate beyond 2029, while FitzPatrick's current license extends to 2034 and Nine Mile Point Unit 2's to 2046. By the information cutoff, CEG had filed Nine Mile Point Unit 1 on March 25, 2026 and Ginna on June 17, 2026; the NRC accepted them for detailed review on April 23 and July 16, respectively. That de-risks late filing, but it does not pre-judge safety or environmental review. [The NRC's subsequent-license-renewal status page](https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal) is the controlling live status source.

Age is another vulnerability. Extension capital and maintenance are prerequisites for preserving the moat. A long license is economically useful only if CEG maintains availability and avoids severe forced outages. ZEC's output-performance mechanism means operational underperformance can reduce both current market revenue and next-tranche support. There is also political review risk: the PSC retained periodic review and can respond if other programs adequately compensate the plants. This is sensible ratepayer protection but weakens the idea of a fully fixed 20-year subsidy.

Overall, the New York moat should preserve participation and a favorable RNF margin through 2031, but it does not justify aggressive revenue growth. The assets are hard to replace; the commodity price is not hard to compete down. The base case therefore gives more confidence to RNF durability than to top-line acceleration.

6. Historical growth rates

CEG discloses no additive product dollars below the regional segment. The single forecast line is therefore the verified `Regional generation and customer portfolio — NYISO`. Every historical dollar below comes from the same specific data-package row; no product dollars are back-solved.

Product / sub-segment	FY2021 rev	FY2022 rev	FY2023 rev	FY2024 rev	FY2025 rev	4-yr CAGR	Most recent annual YoY	Data package cite
Regional generation and customer portfolio — NYISO	$1.575B [§3 New York, FY2021]	$1.595B [§3 New York, FY2022]	$2.021B [§3 New York, FY2023]	$2.050B [§3 New York, FY2024]	$2.190B [§3 New York, FY2025]	8.6% calculated from cited endpoints	6.8% [§3 New York, FY2025 YoY]	2022-2025 Forms 10-K Note 5; data_package §§3-4

Arithmetic checks pass within 2%: $1.575B × 1.013 = $1.595B; $1.595B × 1.267 = $2.021B; $2.021B × 1.014 = $2.049B versus $2.050B reported; and $2.050B × 1.068 = $2.189B versus $2.190B reported. The small differences are rounding. No back-solved row is used. The three-year CAGR from FY2022 to FY2025 is 11.1%; this is elevated by the FY2023 step-up and is not representative of the latest trajectory. The two-year FY2023-FY2025 CAGR is only 4.1%, while Q1 FY2026 revenue growth slowed to 1.2% [data_package §5, New York Q1 FY2026 row].

The margin history is more informative than the top line. RNF margin was 73.7% in FY2021, 66.9% in FY2022, 61.9% in FY2023, 70.9% in FY2024, 73.1% in FY2025, and 73.2% at the TTM anchor [data_package §3, New York table, RNF margin row]. The six-point range over FY2023-FY2025 demonstrates that realized market/hedge/policy/customer mix can swing even without dramatic revenue changes. It also supports using scenario margins rather than a fixed historical average.

7. Management guidance

The verified data package contains no New York-specific revenue, RNF, generation, hedge, contract, or margin guidance. `[DATA GAP: data_package §6 contains no management quote specific to New York.]` That absence matters. It prevents the analyst from importing CEG's companywide long-term contract narrative into New York as if a specific hyperscaler or utility deal had been signed.

The following companywide comments are relevant only as strategy context and are not treated as New York guidance:

- **Q2 FY2025, Joe Dominguez — contract strategy:** “long-term contracts like our Meta and Microsoft deals” are becoming “an ordinary part of our strategy” [data_package §6, Q2 FY2025 Contract strategy row]. Interpretation: CEG is willing to convert merchant nuclear output into long-duration contracted value, but neither named deal is in New York. The base case does not assume a New York deal.
- **Q4 FY2025, Joe Dominguez — contracted fleet:** “executed deals for over 10,000 megawatts of our fleet” [data_package §6, Q4 FY2025 Contracted fleet row]. Interpretation: this supports enterprise-level contracting capability, not a New York contracted-MW figure.
- **Q1 FY2026, Shane Smith — customer scale:** “approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually” [data_package §6, Q1 FY2026 Customer scale row]. Interpretation: the combined company has material customer reach and cross-sell capacity, but New York's share is not disclosed.

The most decision-relevant forward anchor for New York is instead the adopted ZEC 2.0 order and the live NRC process. Those are external regulatory facts, not management guidance. The model uses them to reduce shutdown probability and support margin durability, while reserving contract upside for the bull case.

8. Forward growth assumptions

Base case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Base CAGR TTM→TTM+5y	Justification
Regional generation and customer portfolio — NYISO	11.1% [§3 New York revenue FY2022-FY2025]	1.2% [§5 New York Q1 FY2026]	No New York guide [§6]	2.0%	NYISO demand and nominal price growth support modest expansion, but ZEC/PTC offsets and no disclosed New York contract cap the case.

The 2.0% base CAGR is deliberately below the 11.1% three-year historical figure because the latter includes a 26.7% FY2023 step-up and because the latest quarterly growth is only 1.2%. It is only modestly above that latest print because NYISO baseline energy demand grows from 155,460 GWh in 2026 to 165,640 GWh in 2031, while physical nuclear volume has little structural growth and the ZEC and federal PTC formulas offset part of stronger market receipts. Large-load forecasts are system demand, not CEG sales. The case assumes normal nuclear availability, successful license renewal before expiry, ordinary hedge roll, no major capacity-market redesign windfall, and no specific New York hyperscaler contract.

Base revenue develops as follows:

Date	Revenue	YoY / annual step	Key driver
TTM 2026-03-31	$2.197B	Anchor	Verified data-package TTM
2027-03-31	$2.241B	2.0%	Gradual hedge roll and load growth
2028-03-31	$2.286B	2.0%	Normal operations and rising NYISO demand
2029-03-31	$2.332B	2.0%	ZEC 1.0 through March 2029; renewal transition
2030-03-31	$2.378B	2.0%	ZEC 2.0 bridge and first full calendar tranche

Date	Revenue	YoY / annual step	Key driver
2031-03-31	$2.426B	2.0%	Demand growth partly offset by support phase-down

Bull case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bull CAGR TTM→TTM+5y	Justification
Regional generation and customer portfolio — NYISO	11.1% [§3 New York revenue FY2022-FY2025]	1.2% [§5 New York Q1 FY2026]	No New York guide [§6]	4.0%	Strong large-load realization, firm market prices, and a New York contract opportunity lift growth, with ZEC/PTC offsets still applied.

The bull case is not a return to the historical 11.1% CAGR. A mature nuclear fleet has limited physical volume growth, and the segment has no disclosed New York contract or uprate. Four percent assumes strong NYISO demand realization, attractive Rest-of-State capacity economics, high availability, favorable hedge roll, and at least one meaningful clean-energy or customer contract by 2031. It does not add full PTC, full ZEC, and high market prices simultaneously. ZEC/PTC offsets are respected, so the upside comes from a better realized revenue stack and customer opportunity rather than policy double-counting. The one-point reduction from the draft's 5% explicitly recognizes that support formulas capture part of the upside and that Zone C load forecasts are not contracted CEG volumes.

Date	Revenue	YoY / annual step	Key driver
TTM 2026-03-31	$2.197B	Anchor	Verified data-package TTM
2027-03-31	$2.285B	4.0%	Stronger pricing and availability
2028-03-31	$2.376B	4.0%	Large-load demand begins to monetize
2029-03-31	$2.471B	4.0%	Smooth ZEC transition and contract progress
2030-03-31	$2.570B	4.0%	High realized load plus capacity value
2031-03-31	$2.673B	4.0%	Contracted and merchant stack both favorable

Bear case

Product	3-yr historical CAGR	Latest YoY	Mgmt FY+1 guide	Bear CAGR TTM→TTM+5y	Justification
Regional generation and customer portfolio — NYISO	11.1% [§3 New York revenue FY2022-FY2025]	1.2% [§5 New York Q1 FY2026]	No New York guide [§6]	(2.0%)	Weak capture prices, delayed large loads, an outage cycle, and replacement-power exposure more than offset policy support.

The bear case does not assume permanent plant closure because the PSC has extended ZEC support and both near-dated license-renewal applications were accepted for review. It instead models a commercially plausible disappointment: large loads arrive more slowly, upstate congestion and renewable additions suppress captured energy prices, one material outage cycle reduces output and triggers replacement purchases, and ZEC/PTC protection responds only with formula and timing lags. Revenue contracts 2% annually to $1.986 billion, slightly below FY2023 but well above FY2022. That is a meaningful stress without assuming terminal shutdown; RNF margin takes the larger hit.

Date	Revenue	YoY / annual step	Key driver
TTM 2026-03-31	$2.197B	Anchor	Verified data-package TTM
2027-03-31	$2.153B	(2.0%)	Soft hedge roll and lower capture
2028-03-31	$2.110B	(2.0%)	Delayed loads and renewable pressure
2029-03-31	$2.068B	(2.0%)	Outage cycle and ZEC-transition friction
2030-03-31	$2.027B	(2.0%)	Policy floor limits further erosion
2031-03-31	$1.986B	(2.0%)	Support remains but economics underperform

These paths are thesis-consistent. The base decelerates from the 6.8% FY2025 rate and the 11.1% three-year CAGR toward 2%, consistent with the 1.2% latest quarterly growth and the absence of physical capacity expansion. The bull accelerates from the latest print only with specific load, pricing, availability, and contract mechanisms. The bear allows 2% annual contraction despite support because ZEC and PTC protect eligible economics through formulas; they do not guarantee revenue, remove outage timing, or eliminate replacement-power exposure.

9. Forward RNF margin assumptions

The exact metric is **RNF (Operating revenues net of Purchased power and fuel expenses)**. It is not statutory operating income. The current TTM RNF margin is 73.2% [data_package §3, New York table, TTM column]. No corporate/unallocated RNF, operating and maintenance expense, depreciation, taxes other than income tax, or gain-on-sale item is inserted here.

Case	TTM RNF margin	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31	Change vs TTM
Bear	73.2%	70.0%	68.0%	66.0%	65.0%	64.0%	(920) bps
Base	73.2%	72.8%	72.5%	72.0%	72.0%	72.0%	(120) bps
Bull	73.2%	73.5%	74.0%	74.5%	75.0%	75.0%	+180 bps

Base mechanism. Margin stays close to, but below, current because normal nuclear availability and the ZEC/PTC floor offset routine hedge and customer-mix volatility. The 120-bp decline recognizes that 73.2% is near the top of the annual history, that the latest quarter eased to 71.9%, and that more customer/load activity can raise purchased-power needs even when absolute RNF grows. ZEC 2.0 protects eligible value but its market-revenue and federal-credit offsets prevent the maximum schedule from becoming additive upside. No step-change contract price is assumed.

Bull mechanism. The 180-bp expansion requires more than market inflation. High availability protects ZEC-eligible volume; strong customer or contract realization reduces open merchant exposure; and firm Rest-of-State capacity value improves the gross-margin stack. The 75.0% terminal margin is close to the observed 75.3% Q4 FY2025 quarter but above every full-year margin in the verified history, so it already embeds unusually consistent execution. It does not assume that purchased power, nuclear fuel, outages, or customer balancing disappear. Any new contract must be additive after accounting for ZEC/PTC offsets.

Bear mechanism. The 920-bp decline is caused by a mix of lost owned output, replacement-power purchases, weaker realized pricing, and unfavorable customer balancing. A group output shortfall could reduce the following ZEC tranche cap, amplifying the effect. The 64.0% terminal margin is still 210 bps above FY2023's observed 61.9%, explicitly giving credit to ZEC 2.0 and the federal PTC while no longer treating 68% as a hard floor. A severe multi-unit or prolonged outage could still produce a lower result than modeled.

Margin sensitivity is nonlinear. If market receipts rise, the PTC and ZEC can decline, so not every dollar of stronger commodity pricing becomes incremental RNF. If market receipts fall, support rises but may be subject to formula, timing, tax attributes, output, and review. The model therefore brackets the annual historical range rather than treating the 73.1%-73.2% FY2025/TTM peak as a floor: bear 64.0% is near but above the 61.9% FY2023 trough, base 72.0% is below the current peak, and bull 75.0% requires sustained execution near the best recent quarter.

10. Segment rollup

Because the data package discloses only one additive New York economic unit, the product sum and segment total are identical. This is a disclosure constraint, not an assumption that nuclear, customer, capacity, and policy economics are homogeneous. The scenario build remains bottom-up from the one verified line and ties exactly.

Case	Product line	TTM revenue	Revenue CAGR	TTM+5y revenue	RNF margin	RNF profit	Reconciliation
Bear	Regional generation and customer portfolio — NYISO	$2.197B	(2.0%)	$1.986B	64.0%	$1.271B	Product sum equals segment total
Base	Regional generation and customer portfolio — NYISO	$2.197B	2.0%	$2.426B	72.0%	$1.747B	Product sum equals segment total
Bull	Regional generation and customer portfolio — NYISO	$2.197B	4.0%	$2.673B	75.0%	$2.005B	Product sum equals segment total

Arithmetic ties: bear revenue is `$2.197B × 0.98^5 = $1.986B`; bear RNF is `$1.986B × 64.0% = $1.271B`. Base revenue is `$2.197B × 1.02^5 = $2.426B`; base RNF is `$2.426B × 72.0% = $1.747B`. Bull revenue is `$2.197B × 1.04^5 = $2.673B`; bull RNF is `$2.673B × 75.0% = $2.005B`. Differences from displayed multiplication are rounding only and are below 0.1%.

The base case adds $0.139 billion of RNF from the TTM anchor, a 1.7% annualized increase. That is below revenue CAGR because margin normalizes by 120 bps. The bull adds $0.397 billion, while the bear loses $0.337 billion. These are RNF changes, not changes in operating income. Synthesis must separately forecast corporate/unallocated activity and the statutory operating-cost bridge.

11. Key risks and wildcards

- **NRC license renewal — bear/base.** Nine Mile Point Unit 1 and Ginna applications are accepted for review, but approval is not automatic. Delay, contested environmental issues, or required capital could impair 2031 economics. The base assumes approval with ordinary conditions; the bear assumes cost and timing friction, not forced retirement.
- **Nuclear availability and aging — bear.** A material forced outage reduces energy and capacity value, may require purchased replacement power, and can threaten the ZEC performance threshold. This is the most direct path to a lower RNF margin.
- **ZEC 2.0 implementation and review — bear/base.** The extension is approved, but payments are formulaic, tranche-based, performance-conditioned, and coordinated with other support. Periodic review protects ratepayers and limits over-earning. The model does not treat the maximum price as guaranteed cash.
- **Federal nuclear PTC — bear/base.** The credit declines with gross receipts and is coordinated with ZEC. Tax-law change, eligibility interpretation, or insufficient tax attributes could alter timing or value. Conversely, low receipts increase support, cushioning downside.
- **NYISO market reform — bull/bear.** Separate seasonal capacity products or more granular locational accreditation could better reward winter-reliable nuclear. More granular zones could also expose export-constrained upstate resources to lower local capacity value. Direction depends on final design.
- **Large-load realization — bull/base.** NYISO forecasts major Zone C and statewide large-load growth, but interconnection-queue demand is uncertain. No New York CEG contract is disclosed. The base uses only broad demand support; the bull requires observable load and contracting.
- **Transmission and import additions — bear/base.** CHPE and other transmission can improve system reliability and reduce scarcity, potentially pressuring upstate prices. They can also enable more efficient delivery and reduce congestion. The net RNF effect is uncertain.
- **Renewable and storage deployment — bear.** Large additions can suppress energy capture during certain hours. Yet delays and capacity-accreditation limits preserve firm-generation value. The bear assumes faster deployment and lower capture without assuming nuclear becomes economically irrelevant.
- **Commodity and hedge roll — all cases.** New York reference power and capacity prices are not CEG realized prices. Hedge maturities delay both upside and downside. Monitoring should focus on RNF and realized hedge disclosure, not spot references alone.
- **Customer/load mismatch — bear.** A larger commercial book can create replacement-power and basis risk if load grows in the wrong hours or zones. The current high RNF margin is not proof that future load is costless.
- **Political affordability — bear/base.** ZEC 2.0 currently costs ratepayers roughly $408 million annually across the state fleet, and affordability scrutiny can intensify. Formula offsets and periodic reviews make outright repeal less likely but cap upside.
- **Contract optionality — bull.** A long-duration clean-energy agreement at a New York nuclear site could improve visibility and support reinvestment. It is excluded from base because no counterparty, price, MW, or New York contract is in the verified package.

Monitoring dashboard through 2031

The most useful leading indicators are: NRC milestone status for Nine Mile Point Unit 1 and Ginna; annual nuclear availability and any prolonged outage; ZEC 2.0 implementation filings and actual tranche pricing; federal PTC realization and offset treatment; Rest-of-State capacity prices and accreditation; Zone C large-load commitments; NYISO baseline versus high-load revisions; New York RNF and margin each quarter; and any disclosed New York contract. A base-case breach would occur if RNF margin stays below 68% for four quarters without a clearly temporary outage, a license application is rejected, or policy support is materially weakened without replacement revenue. A move below 68% is a monitoring trigger, not the bear-case floor; the revised bear case permits 64% because FY2023 demonstrated that annual RNF margin can fall to 61.9% even before the modeled outage/ZEC-transition combination.

Scenario summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	$1.986B	RNF (Operating revenues net of Purchased power and fuel expenses)	64.0%	$1.271B	30%
Base	$2.426B	RNF (Operating revenues net of Purchased power and fuel expenses)	72.0%	$1.747B	55%
Bull	$2.673B	RNF (Operating revenues net of Purchased power and fuel expenses)	75.0%	$2.005B	15%

The probabilities are deliberately non-uniform. Base receives 55% because ZEC 2.0 is approved, both near-dated license applications are accepted for NRC review, and the TTM margin is already strong. Bear rises to 30% because the observed FY2023 margin trough, aging assets, outage severity, captured-price pressure, and formula/timing offsets can produce a material RNF shortfall even without closure. Bull falls to 15% because it requires several favorable events together—strong load realization, high availability, constructive capacity economics, and a presently undisclosed New York contract or superior market capture—without double-counting ZEC and PTC. Probability-weighted terminal revenue is $2.331 billion and probability-weighted terminal RNF is $1.643 billion, an implied 70.5% RNF margin; the weighted figures use terminal dollars, not an average of scenario growth rates or margins.

External source record

External research was fetched live for this stage and used only for NYISO market, regulatory, policy, load, and current license-status context. It did not replace or modify CEG historicals, quotations, or classifications from the verified data package.

- [NYISO 2025 Load and Capacity Data Report](https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf), released April 2025; Tables I-1a, I-14, III-2a, and V-2.
- [NYISO 2025 Power Trends](https://www.nyiso.com/documents/20142/2223020/2025-Power-Trends.pdf), reliability and resource-transition context.
- [NYISO MMU 2025 State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/05/NYISO-2025-SOM-Report__5-19-2026-final.pdf), published May 2026.
- [New York PSC Order Extending Zero-Emissions Credit Program](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0012E79B-0000-CA56-B121-646E90864AF9%7D), issued January 22, 2026.
- [New York PSC announcement of ZEC extension](https://dps.ny.gov/news/commission-announces-extension-nuclear-power-credit-program), January 22, 2026.
- [NRC status of subsequent license-renewal applications](https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal), live status checked at the information cutoff.
- [Constellation New York license-renewal announcement](https://www.constellationenergy.com/news/2026/06/constellation-seeks-license-renewals-for-two-new-york-units-through-2049.html), June 26, 2026.

Appendix B6 - ERCOT

ERCOT — Segment Deep Dive

Company: Constellation Energy Corporation **Forecast anchor:** TTM ended 2026-03-31 **Forecast horizon:** 2031-03-31, exactly five calendar years **Exact segment profit basis:** `RNF (Operating revenues net of Purchased power and fuel expenses)` **Reporting scale:** USD billions unless stated otherwise

0. Segment boundary and taxonomy note

ERCOT is Constellation's legacy Texas reportable segment: the regional generation and customer portfolio operating inside the Electric Reliability Council of Texas market. The five-region legacy taxonomy was stable through FY2025. Calpine became a sixth, separate reportable segment after the acquisition closed on January 7, 2026; therefore, Calpine-owned Texas plants, retail activity, development projects, and the Pin Oak Creek peaker remain in the Calpine segment unless the issuer later restates the taxonomy. They are economically relevant competitors, complements, and shared corporate resources, but they are **not** allocated into this ERCOT forecast. This boundary is the most important modeling guardrail because a combined-company discussion of "ERCOT" can easily be mistaken for the accounting segment. The forecast below uses only the legacy ERCOT TTM revenue of $1.876 billion and TTM RNF of $1.132 billion, calculated on the issuer's Note 5 segment basis from the [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm) and [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm), as sealed in data_package §1, rows 103-118 and §3, rows 166-171.

1. What this segment actually is

ERCOT is an integrated regional power book, not one plant and not a conventional product line. It combines the economics of owned generation, contracted generation or supply, wholesale market participation, retail and commercial customer obligations, purchased power, fuel procurement, congestion management, environmental products, and hedging within Texas's largely isolated electricity grid. A customer may buy fixed-price electricity, shaped power, renewable attributes, natural gas, or a customized structured product. The segment then matches that obligation against output from its own fleet, market purchases, fuel contracts, financial hedges, and bilateral transactions. The customer contract supplies a revenue stream; the generation portfolio supplies physical power and optionality; the commercial desk reconciles differences in volume, timing, location, weather, and price.

Texas differs from PJM, NYISO, and ISO-New England because ERCOT has no centralized capacity market. A generator principally earns energy revenue, ancillary-service revenue, congestion value, and contract margin. Scarcity prices are intended to compensate flexible and reliable assets when supply is tight, rather than paying every qualified plant a forward capacity price. ERCOT's real-time market dispatches resources every five minutes, while the day-ahead market allows participants to take financial positions in energy and ancillary services. The Independent Market Monitor describes a system serving more than 27 million customers, coordinating more than 1,460 generating resources across more than 55,000 miles of transmission [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf).

The physical foundation is unusually diverse for a single regional merchant portfolio. Constellation's current official site description says it owns 44% of the 2,645 MW South Texas Project, equal to about 1,100 MW of carbon-free baseload nuclear capacity [Constellation South Texas Project](https://www.constellationenergy.com/about/locations/south-texas-project.html). The company's Texas asset fact sheet also identifies 3,520 MW of legacy natural-gas generation at Colorado Bend II, Wolf Hollow II, and Handley, plus 169 MW of wind at Whitetail and Sendero [Constellation Texas fact sheet](https://www.constellationenergy.com/content/dam/constellationenergy/landing-pages/public-policy/231107ConstellationFactSheet-TX.pdf). Those figures broadly reconcile to the Justice Department's description of approximately 5,000 MW of legacy Constellation capacity in ERCOT [DOJ Calpine settlement announcement](https://www.justice.gov/opa/pr/justice-department-requires-divestitures-proceed-constellations-proposed-266-billion). They describe present business composition, not a second source for the data package's historical revenue or RNF.

The asset mix matters. Nuclear can run through most hours at low incremental fuel cost and produces carbon-free attributes, while combined-cycle gas plants can follow load and monetize evening ramps, low-renewable periods, ancillary services, and

local congestion. Peaking and older steam units provide scarcity optionality but face higher heat rates and fixed-maintenance burdens. Wind contributes zero-fuel output but also suffers from basis and capture-price pressure when correlated renewable production is high. Retail and commercial load turns some generation output into a natural hedge: when wholesale prices rise, generation earns more while the cost of serving fixed-price load rises; when prices fall, retail procurement becomes cheaper while merchant generation earns less. The result is a portfolio whose economics depend more on shape and risk management than on annual average power prices alone.

Go-to-market is through direct commercial relationships, retail channels, wholesale counterparties, and ERCOT's centralized markets. The segment is not disclosed with separate generation, retail, and trading revenue lines, so the analysis must remain at the regional portfolio level. `[DATA GAP: CEG does not disclose ERCOT-specific customer count, retail load in MWh, owned generation in MWh, generation-to-load matching ratio, or revenue by generation/retail/trading sub-product in the verified data package.]`

2. Current economics

TTM revenue ended 2026-03-31 at **$1.876 billion**, with **$1.132 billion of RNF (Operating revenues net of Purchased power and fuel expenses)** and a **60.3% RNF margin**, calculated from the issuer's Note 5 tables in the [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm) and [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm) [data_package §1, row 112; §3, rows 166-171]. FY2025 revenue was $1.904 billion, up 22.8%, while FY2025 RNF was $1.137 billion and the RNF margin was 59.7% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). The near equality of FY2025 and TTM totals hides a sharp quarterly change: Q2, Q3, and Q4 FY2025 revenue grew 30.0%, 20.1%, and 18.9%, respectively, but Q1 FY2026 revenue fell 7.0% year over year. Q1 RNF margin was still 56.5% [Q1 FY2026 Form 10-Q, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm). That pattern is consistent with a hedged regional portfolio in which market conditions change before contracted and hedge economics fully roll through earnings.

Historical RNF demonstrates both the upside and the danger of treating a merchant portfolio as a stable-margin utility. RNF rose from $0.582 billion in FY2023 to $1.047 billion in FY2024 and $1.137 billion in FY2025, while margin rose from 43.2% to 67.5% and then normalized to 59.7% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). FY2021 RNF was negative $0.825 billion and the margin was negative 69.9% [2022 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm), a reminder that extreme weather, fuel and purchased-power obligations, hedge mismatches, and customer load shape can overwhelm normal economics. The model does not extrapolate the unusually high FY2024 margin or assume that the nuclear asset converts every power-price increase into RNF.

The finest disclosed economic unit is simply "Regional generation and customer portfolio — Texas energy-only market" [data_package §4, row 270]. There is no additive sub-product revenue table. That non-disclosure prevents a clean split between South Texas Project nuclear output, legacy gas output, wind, retail, and wholesale activity. It also means that segment margin is a portfolio result, not a physical gross margin for any one fleet technology.

Capital intensity is high in economic terms. Nuclear ownership requires refueling, planned and unplanned maintenance, life-extension work, decommissioning funding, security, and regulatory compliance. Gas assets require major maintenance, emissions compliance, fuel-delivery arrangements, and periodic turbine overhauls. Wind assets require sustaining maintenance and may require transmission or congestion mitigation. Retail and trading activities are less plant-intensive but consume working capital, collateral capacity, credit limits, and technology spend. `[DATA GAP: Segment-specific maintenance capex, growth capex, invested capital, working capital, collateral, and depreciation are not disclosed for ERCOT in the verified data package.]` Therefore, RNF should not be mistaken for free cash flow or for statutory profit. Corporate and operating bridge items are modeled once in the synthesis, not allocated here.

The latest reported North ERCOT day-ahead around-the-clock reference price was $32.94/MWh in FY2025, versus $26.97/MWh in FY2024, $55.15/MWh in FY2023, $64.38/MWh in FY2022, and $146.63/MWh in FY2021 [2025 Form 10-K, Market and Commodity Price Risk table](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm); earlier values are cross-checked in data_package §0a, rows 67-77. These are reference prices, not Constellation realized prices. RNF already

incorporates generation, retail load, hedges, fuel and purchased power, ancillary services, and congestion. [DATA GAP: Realized ERCOT energy, ancillary-service, capacity-equivalent, and congestion prices are not disclosed as a clean historical series.]

3. Unit economics

The segment's first unit-economic engine is the **generation spread**. For nuclear and wind, incremental fuel cost is low, so realized power and ancillary prices above operating and sustaining costs can create substantial contribution. For gas generation, the relevant variable is the market heat rate: power price minus the natural-gas price multiplied by plant heat rate, less variable operations, emissions, and transport. Efficient combined-cycle plants can remain economic in many hours, while older steam and peaking units rely more on high-price hours, reliability commitments, and ancillary services. Location changes the spread because congestion can separate a plant's nodal price from a system hub price.

The second engine is the **load-serving spread**. A fixed-price retail or commercial contract creates revenue based on contracted volume and shape. The cost to serve includes owned generation valued at market, bilateral purchases, ERCOT settlements, renewable attributes, transmission and distribution pass-throughs where applicable, ancillary allocations, credit, customer acquisition, and bad debt. Profit improves when the portfolio accurately forecasts weather and customer behavior and matches supply to load. It weakens when load is unexpectedly high in expensive hours, customers churn after hedges are placed, or basis and congestion cause the supply hedge to settle at a different location than the customer obligation.

The third engine is **commercial optimization and hedging**. Constellation's three-year ratable merchant sales plan was historically around 90%/60%/30%, and year-end coverage was 94%-97% for the next year and 75%-78% for the following year across its major regions, including ERCOT [2022 Form 10-K, Market and Commodity Price Risk](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm); data_package §0a, rows 90-98. Those percentages are historical benchmarks, not current segment disclosure. The economic point is still important: near-term RNF is partly insulated from prompt prices, but outer-year economics progressively reopen. A hedge reduces price risk but introduces volume, shape, basis, collateral, and counterparty risk; it never converts merchant output into a risk-free annuity.

The fourth engine is **scarcity and flexibility**. ERCOT's energy-only design rewards resources that can be available in tight hours. Gas plants can monetize fast ramping, responsive reserve, ERCOT Contingency Reserve Service, non-spin, and other services. Nuclear produces reliable baseload but is less suited to frequent cycling; its value is high availability and low marginal cost. Batteries increasingly compete for ancillary services and evening ramps. The 2025 Independent Market Monitor report found more than 17,000 MW and 31,500 MWh of battery capacity by year-end, up almost 80%, while annual revenue per unit of battery capacity fell 37% as ancillary competition intensified. Storage is therefore both a competitor that compresses gas scarcity rents and a market resource that can make the system more reliable [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf).

The fifth engine is **renewable capture and residual-load shape**. More than 6 GW of solar entered ERCOT in 2025. Solar generation increased 49%, its share rose from 10.4% to 13.9%, and 6% of potential solar generation was curtailed. Midday renewable output lowers prices and can create negative-price periods; as solar falls in the evening, gas, storage, and firm generation become more valuable. The EIA expects ERCOT utility-scale solar generation to grow from 56 BkWh in 2025 to 106 BkWh by 2027 and battery capacity to expand from about 15 GW to 37 GW [EIA January 2026 outlook](https://www.eia.gov/todayinEnergy/detail.php?id=67005). The implication is two-sided: low-cost renewables reduce average capture prices and thermal run hours, but rapid load growth can expand the size of the evening net-load ramp and preserve dispatchable-gas value.

Margins move up when contracted pricing captures reliability or carbon-free value, customer load is well matched to owned supply, gas plants achieve high availability during tight hours, congestion is favorable, nuclear operates reliably, and hedges protect against weak prompt markets. Margins move down when renewable and battery additions outrun demand, gas input costs rise faster than power, retail load is short in scarce hours, outages coincide with high prices, congestion isolates generation, or collateral and credit costs rise. Because RNF subtracts purchased power and fuel but not operating and maintenance, depreciation, or taxes other than income taxes, a higher RNF margin still does not prove higher statutory operating profitability.

4. Competitive dynamics

Vistra

Vistra is the most formidable integrated competitor. Its 2025 Form 10-K describes approximately five million residential, commercial, and industrial retail customers across its footprint and 43,641 MW of generation capacity. Its Texas business combines ERCOT generation with a large retail platform. Vistra explicitly says retail sales and hedging are critical because of natural-gas and market-heat-rate volatility, and that its integrated generation-retail structure provides an effective sales channel. At December 31, 2025, its Texas nuclear/renewable/coal generation was 100% hedged for both 2026 and 2027; Texas gas generation was 92% hedged for 2026 and 43% for 2027 [Vistra 2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1692819/000169281926000006/vistra-20251231.htm). That disclosure is a useful competitive benchmark: sophisticated peers protect the prompt years but retain growing outer-year exposure.

Vistra's advantage is scale, brand breadth, trading liquidity, and the ability to match a large retail book against diverse generation. It can acquire customers, spread technology and risk-management costs, and hold collateral more efficiently than a small standalone generator. Its weakness is exposure to the same commodity and regulatory cycles, plus legacy coal and gas maintenance. Constellation's nuclear share and carbon-free commercial positioning differentiate it, but its legacy Texas retail scale appears smaller than Vistra's and is not separately updated in the verified package.

NRG

NRG is another integrated Texas benchmark. Its 2025 Form 10-K reports about eight million residential customers across retail energy and smart-home offerings, roughly 12 GW of core generation primarily in Texas, and the largest share of competitively served residential electric customers in Texas. NRG says its Texas generation supply is fully integrated with retail load, reducing third-party purchases, transaction costs, credit exposure, collateral, and earnings volatility. It was advancing a 415 MW peaker for 2026 and two additional gas projects totaling 1,132 MW for 2028 [NRG 2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1013871/000101387126000004/nrg-20251231.htm). NRG therefore competes for retail customers, shaped products, development sites, gas equipment, interconnections, and large-load contracts.

NRG's customer density and consumer-channel experience are difficult to replicate quickly. Its planned generation also signals that incumbent retailers see value in owning dispatchable supply against growing load. For Constellation, this raises the bar for retail customer acquisition and prevents the segment from assuming that Texas load growth automatically becomes its revenue growth. The relevant question is market share of profitable, shaped load, not statewide electricity consumption alone.

Calpine overlap inside Constellation

Calpine is now under common ownership but remains a separate accounting segment. Before the merger, DOJ described Calpine as the third-largest ERCOT generator with about 9,000 MW, versus about 5,000 MW for legacy Constellation. The combined position was large enough that DOJ and Texas required divestiture of the Jack A. Fusco and Gregory gas plants, along with four PJM facilities, to address the risk of profitable withholding and higher prices [DOJ settlement announcement](https://www.justice.gov/opa/pr/justice-department-requires-divestitures-proceed-constellations-proposed-266-billion). The final judgment was entered in May 2026 [DOJ case page](https://www.justice.gov/atr/case/us-and-plaintiff-states-v-constellation-energy-corporation-et-al).

Common ownership can still improve commercial capabilities: broader customer relationships, deeper gas procurement, more dispatchable assets, more collateral netting, and a larger development platform. Yet this appendix assigns **zero** Calpine revenue, RNF, capacity, or growth projects to ERCOT. Shared systems or customer cross-selling can benefit the legacy segment only if evidenced in its future disclosed results. The divestitures also demonstrate that scale has a regulatory ceiling; management cannot maximize Texas market power without scrutiny. The base case assumes modest commercial benefits but no explicit synergy uplift. The bull case allows better customer capture and hedge execution, not transferred Calpine economics.

Other competitors and substitutes

Renewable developers, battery owners, municipal utilities, cooperatives, demand-response aggregators, and large customers with behind-the-meter generation all compete with parts of the portfolio. Solar and wind undercut energy prices when available. Batteries compete directly for ancillary services and evening spreads. Flexible cryptocurrency load can curtail when prices are high, reducing scarcity. Hyperscale data centers can sign directly with generators, build onsite generation, or choose another state. Transmission expansion can reduce local congestion rents. These are not fringe substitutes: in 2025, ERCOT added 14.8 GW of capacity, comprising 6.2 GW solar, 7.3 GW storage, 1.2 GW wind, and only 280 MW gas [2025 ERCOT State of the Market

Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf).

Pricing power is therefore episodic rather than structural. A plant with scarce location, firm fuel, or high reliability can earn attractive rents in specific hours. A retailer with differentiated products and a sticky customer can retain margin. But annual average power remains a commodity, and new supply or transmission can erode advantage. The best defense is portfolio integration and contracting, not ownership of a generic megawatt.

5. Moat at the segment level

The segment has a **moderate asset-and-portfolio moat**, not a wide franchise moat. The strongest protection is the installed base. Existing nuclear and gas sites already have land, permits, transmission interconnections, operating organizations, and market registrations. Replicating a nuclear plant is economically and politically difficult; South Texas Project's long-lived carbon-free output is particularly scarce. Existing gas sites can also be valuable for uprates, replacement units, storage, and data-center interconnection because transmission access is often the true bottleneck.

The second protection is integrated risk management. A portfolio containing baseload nuclear, flexible gas, wind, and customer load can absorb more shapes than a single-asset generator. It can sell a fixed block, follow a customer's hourly demand, source renewable attributes, and manage deviations through multiple assets and market products. This creates a commercial capability moat built from systems, credit, data, and experienced people. The historical three-year ratable sales framework supports cash-flow visibility, although current ERCOT coverage is not disclosed [2022 Form 10-K, Market and Commodity Price Risk](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm).

The third protection is customer switching friction and credit reputation. Large commercial customers care about performance, collateral, customized structures, renewable claims, and the counterparty's ability to survive extreme markets. Constellation's national scale and investment-grade objective matter. However, Vistra, NRG, and other sophisticated providers possess similar capabilities, so this is an oligopolistic advantage rather than exclusivity.

The moat is weakened by four forces. First, the wholesale product is homogeneous: one MWh is substitutable after location, timing, and attributes are standardized. Second, batteries and renewables are entering faster than conventional generation and can compress both energy and ancillary margins. Third, competitors have larger Texas retail franchises. Fourth, regulatory remedies already constrain market concentration. DOJ's required Texas divestitures confirm that market-power economics cannot be treated as a durable shareholder advantage.

Durability over five to ten years is therefore conditional. The asset base should remain valuable if Texas load grows, transmission remains constrained, and reliable generation earns appropriate scarcity or contract value. South Texas Project can provide low-carbon baseload beyond the forecast horizon. But the RNF margin is not protected from cycles; FY2021's negative RNF and FY2024's 67.5% margin show how wide the range can be [2022 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm) and [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). A durable moat would produce consistently high returns without relying on price spikes. ERCOT has not demonstrated that profile. The correct segment verdict is **moderate moat, high cyclicality, strong strategic assets, limited evidence of stable pricing power**.

6. Historical growth rates

CEG discloses no additive product hierarchy below the geography. The finest dollar-disclosed line is the entire ERCOT regional generation and customer portfolio. The required historical table therefore contains one economic unit; no nuclear, gas, wind, retail, or trading dollars are invented.

Product / sub-segment	FY2023 revenue	FY2024 revenue	FY2025 revenue	FY2023-FY2025 CAGR	Most recent annual YoY	Data package cite
Regional generation and customer portfolio	$1.346B	$1.550B	$1.904B	18.9%	22.8%	[2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm); data_package §3, rows 166-171 and §4, row 270

Arithmetic checks: $1.346B × 1.152 = $1.551B, within 0.1% of the disclosed $1.550B. $1.550B × 1.228 = $1.903B, within 0.1% of the disclosed $1.904B. The FY2023-FY2025 CAGR is `(1.904 / 1.346)^(1/2) - 1 = 18.9%`. All checks are inside the 2% tolerance. No row was back-solved.

The five-year context is deliberately not summarized as a smooth CAGR. Revenue was $1.181 billion in FY2021, $1.543 billion in FY2022, $1.346 billion in FY2023, $1.550 billion in FY2024, and $1.904 billion in FY2025; RNF ranged from negative $0.825 billion to positive $1.137 billion [2022 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm) and [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). The path is volatile enough that a single historical CAGR would imply false stability. The forward model therefore starts from the TTM anchor and uses explicit market drivers rather than continuing 18.9%.

`[DATA GAP: The verified data package has no dollar-disclosed ERCOT sub-product history for nuclear generation, gas generation, wind, retail load, wholesale trading, ancillary services, or congestion.]`

7. Management guidance

There is no issuer-provided FY2026 revenue or RNF guide for the legacy ERCOT accounting segment. The relevant statements in the verified data package are portfolio and combined-company anchors. They are reproduced here without re-fetching transcripts.

- **Contract strategy — Q2 FY2025 call, 2025-08-07, Joe Dominguez:** “long-term contracts like our Meta and Microsoft deals” are becoming “an ordinary part of our strategy” [data_package §6, row 322]. Interpretation: contracting is a repeatable corporate tool, but neither named contract is allocated to legacy ERCOT. The forecast gives the segment credit only for general commercial capability.
- **Calpine hedges — Q3 FY2025 call, 2025-11-07, Dan Eggers:** “near-term open exposure is relatively limited” [data_package §6, row 323]. Interpretation: combined-company Texas gas economics should not be immediately marked to weak prompt prices. This quote refers to Calpine exposure and is not a quantified hedge ratio for the ERCOT segment.
- **Contracted fleet — Q4 FY2025 call, 2026-03-31, Joe Dominguez:** “executed deals for over 10,000 megawatts of our fleet” [data_package §6, row 324]. Interpretation: a substantial part of the combined fleet has longer-duration revenue visibility. The issuer does not disclose how many of those megawatts belong to legacy ERCOT.
- **Thermal base — Q4 FY2025 call, 2026-03-31, Shane Smith:** “minimum expected gross margin and volume grounded in historical experience” [data_package §6, row 328]. Interpretation: Calpine planning uses a downside-aware base rather than full spot upside. The same prudence supports normalizing the legacy ERCOT forecast margin below the FY2024 peak.
- **ERCOT hedge — Q1 FY2026 call, 2026-05-11, Andrew Novotny:** “we've been well hedged and protected against it” [data_package §6, row 331]. Interpretation: near-term weak ERCOT forwards need not translate immediately into consolidated Texas RNF. Because Novotny leads Calpine, this is not evidence of the legacy segment's exact open position.
- **Customer scale — Q1 FY2026 call, 2026-05-11, Shane Smith:** “approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually” [data_package §6, row 332]. Interpretation: the combined commercial platform has substantial cross-sell and portfolio-optimization scale, but the issuer does not allocate the volume to ERCOT versus Calpine or other regions.

`[DATA GAP: No management FY+1 guide is disclosed for ERCOT revenue, RNF, RNF margin, generation volume, retail load, hedge percentage, realized price, or segment capex.]`

8. Forward growth assumptions

The one forecast line is the disclosed regional portfolio. Each scenario compounds exactly five years from TTM revenue of $1.876 billion at 2026-03-31 to 2031-03-31. Revenue is modeled rather than MWh because the package does not disclose segment volume, realized price, or product mix. The growth rate represents the combined effect of load, price, customer share, contract mix, and gross settlement presentation.

Base-case revenue growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Base CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	18.9% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	22.8% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	No segment guide [data_package §6]	3.0%	Strong load and contracting are more than offset at the segment-dollar level by solar/storage entry, retail competition, lower capture prices, and normalization from high 2024-2025 conditions.

The base case decelerates sharply from the historical 18.9% because that rate captures recovery and price/mix volatility, not a durable volume trend. ERCOT average load grew 6.1% in 2025, but 14.8 GW of new supply entered and the Independent Market Monitor found less genuine shortage pricing [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). The segment is assumed to grow materially below system load because statewide load growth does not automatically raise gross segment revenue when power prices and capture rates soften, and because Vistra, NRG, Calpine, renewables, and batteries compete for the same customers and spreads. Contracting and the existing customer portfolio support a positive 3.0% CAGR, but no unallocated Calpine cross-sell is credited.

Bull-case revenue growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Bull CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	18.9% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	22.8% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	No segment guide [data_package §6]	6.0%	Large-load growth materializes, legacy ERCOT wins shaped commercial load, and contract value offsets—but does not reverse—renewable capture erosion and retail competition.

The bull case remains far below the recent 18.9% CAGR and no longer assumes that a favorable load regime produces 8% annual segment-dollar growth. It assumes data centers, oil and gas electrification, population, and industrial projects turn into served load rather than speculative interconnection requests. EIA expects ERCOT gas generation to increase 23% from 2025 to 2027 even as solar rises, illustrating that renewable growth and dispatchable growth can coexist when load expands [EIA January 2026 outlook](https://www.eia.gov/todayinEnergy/detail.php?id=67005). Constellation's nuclear-plus-gas mix captures valuable round-the-clock and evening products, but the 6.0% path requires legacy ERCOT itself—not Calpine or unallocated commercial activity—to retain market share and win priced-for-risk contracts.

Bear-case revenue growth

Product	FY2023-FY2025 historical CAGR	Latest annual YoY	Management FY+1 guide	Bear CAGR TTM to TTM+5y	Justification
Regional generation and customer portfolio	18.9% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	22.8% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm)	No segment guide [data_package §6]	(2.0%)	Projected large loads arrive late, solar/storage suppress capture and scarcity, and competitors retain the best retail customers while gross power-sale dollars reprice lower.

The bear case does not recreate FY2021 in perpetuity. Instead, it assumes a structurally softer terminal revenue base: renewable and battery entry exceeds realized demand, transmission reduces favorable congestion, and prompt hedges roll off into weaker prices. The Independent Market Monitor found 35% of real-time generation capacity offered at or below $0 in 2025 and no primary-reserve hours below 3,000 MW since 2023, evidence that scarcity can disappear even amid load growth [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf).

Explicit annual revenue path

Case	TTM 2026-03-31	2027-03-31	2028-03-31	2029-03-31	2030-03-31	TTM+5y 2031-03-31
Bear	$1.876B	$1.838B	$1.802B	$1.766B	$1.730B	$1.696B
Base	$1.876B	$1.932B	$1.990B	$2.050B	$2.111B	$2.175B
Bull	$1.876B	$1.989B	$2.108B	$2.234B	$2.368B	$2.511B

This year-by-year schedule is the thesis-consistency check. The base and bull cases do not hide a sudden terminal jump. The bear does not assume a one-year collapse followed by unexplained recovery. Each path is a constant revenue CAGR; margin carries the more severe commodity and shape sensitivity. Relative to the initial draft, the terminal revenue range is reduced because system load growth is not the same thing as legacy ERCOT revenue growth and because no bridge allocation permits Calpine's Texas scale to be used as a revenue plug.

Load, supply, and regulatory interpretation

Load growth is the largest positive variable. ERCOT's 2025 Capacity, Demand and Reserves process incorporated a new load forecast, Effective Load Carrying Capability for wind, solar, and storage, and multiple scenarios because the timing of large loads and Texas Energy Fund generation is uncertain [ERCOT CDR release](https://www.ercot.com/news/release/02132025-ercot-releases-capacity). The older planning case showed rapidly tightening margins, but the 2025 market monitor observed actual operating reserves rising because supply additions outpaced demand. Both can be true: long-term interconnection requests may be enormous, while near-term scarcity remains modest. The forecast therefore does not convert an ERCOT planning forecast into segment revenue dollar-for-dollar.

Renewables and storage change **shape**, not only annual totals. EIA reported that wind and solar met 36% of ERCOT demand in the first nine months of 2025; solar averaged 24 GW around noon in summer, double 2023, while battery discharge averaged 4 GW at 8 p.m. [EIA October 2025 analysis](https://www.eia.gov/todayinEnergy/detail.php?id=66464). That reduces midday gas generation and compresses evening price spikes, but it also makes firm nuclear, flexible gas, and well-shaped retail hedges valuable. The base case treats these forces as largely offsetting for revenue but materially negative for RNF margin once current hedges and contracts roll.

Texas Senate Bill 6 adds another uncertainty. The enrolled bill requires planning and cost responsibility for large loads, notice and conditions for co-locating new large loads with existing generation, curtailment capability during firm load shed, and a reliability service for eligible loads of at least 75 MW [Texas SB 6 enrolled text](https://capitol.texas.gov/tlodocs/89R/billtext/html/SB00006F.htm). These rules can improve forecast credibility and protect reliability, but they may slow or reshape projects. The bull assumes compliant projects still connect; the bear assumes delays and compulsory flexibility reduce scarce-hour load.

9. Forward RNF margin assumptions

Exact basis: RNF (Operating revenues net of Purchased power and fuel expenses)

Current TTM RNF margin is 60.3% on the exact sealed basis, calculated from the issuer's Note 5 tables in the [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm) and [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm) [data_package §3, rows 166-171]. The margin is forecast at the portfolio level because no sub-product revenue or RNF is disclosed. No corporate, unallocated, operating-expense, depreciation, tax, or statutory-bridge adjustment is inserted here.

Case	Exact profit basis	TTM profit margin	TTM+5y profit margin	Change	Specific mechanism
Bear	RNF (Operating revenues net of Purchased power and fuel expenses)	60.3%	36.0%	(2,430) bps	Prompt hedges roll into lower capture prices; storage and RTC+B reduce scarcity/ancillary rents; unfavorable retail shape, congestion, and outages raise purchased-power exposure.
Base	RNF (Operating revenues net of Purchased power and fuel expenses)	60.3%	52.0%	(830) bps	Load and contracting support gross value, but renewable/storage competition, RTC+B efficiency, retail competition, and scarcity normalization pull the spread below the FY2024-TTM peak regime.
Bull	RNF (Operating revenues net of Purchased power and fuel expenses)	60.3%	60.0%	(30) bps	High-value shaped contracts, strong nuclear availability, evening gas flexibility, and disciplined hedging preserve approximately the current spread despite structural storage and solar pressure.

The **base** declines 830 basis points because 60.3% follows unusually strong FY2024-FY2025 economics and Q1 FY2026 had already eased to 56.5% [Q1 FY2026 Form 10-Q, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm). A 52.0% terminal margin remains above FY2023's 43.2% because South Texas Project ownership, the existing generation/customer portfolio, and contracting provide a stronger floor, but it does not capitalize peak-period RNF as a durable franchise margin. Hedges and customer contracts delay rather than eliminate exposure to lower capture prices, more storage, and retail competition.

The **bull** holds a 60.0% margin, approximately the current TTM level and below the FY2024 margin of 67.5% [2025 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm). This is deliberately stricter than the initial 65.0% case: RTC+B and rapidly growing storage should make repeated artificial scarcity rents less defensible even when load is strong. Preserving 60.0% still requires high nuclear availability, realized large-load contracts, favorable retail/generation matching, gas assets capturing evening net-load value, and no major congestion dislocation. It does not assume generic commodity inflation; higher gas prices can increase nominal power prices while leaving heat-rate margin unchanged or worse.

The **bear** reaches 36.0%, between FY2022's 26.4% and FY2023's 43.2%, rather than stopping near the latter as the initial 44.0% case did. It assumes a persistent oversupply/weak-scarcity regime rather than a single catastrophic event. Battery competition is material: the Independent Market Monitor reported that operating reserves increased by roughly 1,945 MW per year since 2022 and primary reserves were below 6,500 MW for only 102 hours in 2025 [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). A 36.0% RNF margin still acknowledges nuclear PTC support, retail hedging, and the value of existing sites; it is not an FY2021 tail-event margin.

Annual RNF margin and profit path

Case / exact metric	2027-03-31	2028-03-31	2029-03-31	2030-03-31	TTM+5y 2031-03-31
Bear RNF (Operating revenues net of Purchased power and fuel expenses) margin	54.0%	48.0%	42.0%	38.0%	36.0%
Bear RNF (Operating revenues net of Purchased power and fuel expenses)	$0.993B	$0.865B	$0.742B	$0.658B	$0.610B
Base RNF (Operating revenues net of Purchased power and fuel expenses) margin	57.0%	55.0%	54.0%	53.0%	52.0%
Base RNF (Operating revenues net of Purchased power and fuel expenses)	$1.101B	$1.095B	$1.107B	$1.119B	$1.131B
Bull RNF (Operating revenues net of Purchased power and fuel expenses) margin	58.0%	58.5%	59.0%	59.5%	60.0%
Bull RNF (Operating revenues net of Purchased power and fuel expenses)	$1.153B	$1.233B	$1.318B	$1.409B	$1.506B

This schedule makes the margin transition visible. In the bear, the larger adjustment occurs as near-term contracts and hedges roll, while the terminal years stabilize. In the base, normalization is gradual and revenue growth is substantially offset by margin pressure, leaving terminal RNF roughly flat with the $1.132 billion TTM anchor. In the bull, the margin first absorbs Q1 weakness and then recovers only as contracts and load are assumed to materialize. The profit line equals annual forecast revenue multiplied by the stated RNF margin in every cell.

Regulatory margin drivers

Real-Time Co-optimization plus Batteries went live on December 5, 2025. ERCOT now co-optimizes energy and ancillary services, models battery state of charge, and uses Ancillary Service Demand Curves in place of the old Operating Reserve Demand Curve scarcity adder. The Independent Market Monitor says ASDCs become the primary scarcity-pricing mechanism and observed infrequent shortages in the early post-launch period [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). Efficient co-optimization should reduce artificial scarcity and manual deployment distortions. That is socially positive but can reduce windfall RNF for generators that benefited from inefficient reserve withholding.

The PUCT reliability standard and prospective Dispatchable Reliability Reserve Service can support flexible assets, but out-of-market procurement can also mute energy-only price signals. The base gives no unannounced subsidy or reserve-payment uplift. Texas Energy Fund projects are similar: they may improve system reliability and create development opportunity, but new gas capacity competes with legacy assets. ERCOT noted that 9,720 MW of TEF generation did not meet base-case inclusion rules in its early 2025 CDR but appeared in alternative scenarios [ERCOT CDR release](https://www.ercot.com/news/release/02132025-ercot-releases-capacity). The bull does not assume both shortage pricing and full subsidized capacity growth.

Transmission also matters. The Independent Market Monitor reported more than $14 billion of endorsed transmission projects in 2025, 271% above 2024. New transmission can reduce reliability constraints and expand load, but it can also eliminate favorable nodal premiums. The Houston zone's illustrative combustion-turbine net revenue was about $59/kW-year in 2025 versus $177/kW-year in the import-constrained West zone [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). Because Constellation's legacy assets are not concentrated in the Permian, the model does not grant West-zone congestion rents.

10. Segment rollup

The rollup is bottom-up at the finest disclosed unit. Because the regional portfolio is the only dollar-disclosed product line, product revenue equals segment revenue. The arithmetic is transparent and does not allocate Calpine, Pin Oak Creek, corporate activity, or statutory bridge items.

Case	Product / sub-segment	TTM revenue	TTM to TTM+5y CAGR	TTM+5y revenue	Exact profit basis	TTM+5y margin	TTM+5y profit
Bear	Regional generation and customer portfolio	$1.876B	(2.0%)	$1.696B	RNF (Operating revenues net of Purchased power and fuel expenses)	36.0%	$0.610B
Bear	Segment total	$1.876B	(2.0%)	$1.696B	RNF (Operating revenues net of Purchased power and fuel expenses)	36.0%	$0.610B
Base	Regional generation and customer portfolio	$1.876B	3.0%	$2.175B	RNF (Operating revenues net of Purchased power and fuel expenses)	52.0%	$1.131B
Base	Segment total	$1.876B	3.0%	$2.175B	RNF (Operating revenues net of Purchased power and fuel expenses)	52.0%	$1.131B
Bull	Regional generation and customer portfolio	$1.876B	6.0%	$2.511B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.0%	$1.506B
Bull	Segment total	$1.876B	6.0%	$2.511B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.0%	$1.506B

Arithmetic tie-outs: bear revenue is `$1.876B × 0.98^5 = $1.696B`, and `$1.696B × 36.0% = $0.610B`. Base revenue is `$1.876B × 1.03^5 = $2.175B`, and `$2.175B × 52.0% = $1.131B`. Bull revenue is `$1.876B × 1.06^5 = $2.511B`, and `$2.511B × 60.0% = $1.506B`. Product and segment totals reconcile exactly because there is one disclosed unit; the difference is 0.0% in every case.

Base RNF is approximately flat over five years despite 3.0% revenue growth because margin normalizes. Bull RNF grows about 5.9% annually as revenue expands while margin merely returns to the current neighborhood. Bear RNF falls about 11.6% annually because weak prices, poor shape, and competitive retail procurement first hit the net-of-fuel-and-purchased-power spread. This asymmetry is economically more realistic than applying the same margin in all cases and avoids treating the recent 60% RNF margin as a protected floor.

11. Key risks and wildcards

- **Scarcity disappears despite load growth — bear.** Solar and storage additions can exceed realized demand, raising reserves and reducing price spikes. In 2025, ORDC contributed less than $0.02/MWh to average real-time energy price, and the reliability deployment price adder added only $0.41/MWh, evidence of limited genuine scarcity [2025

ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). A merchant model that capitalizes rare spikes as recurring margin will overstate RNF.

- **Large-load forecasts fail to materialize — bear.** Data centers, cryptocurrency mines, hydrogen, LNG, and oil-and-gas electrification can submit multiple interconnection requests or connect later than planned. SB 6 explicitly addresses duplicate requests, cost responsibility, and curtailment, showing policymakers also question forecast credibility. Delayed load reduces revenue growth and weakens scarcity.

- **Large-load growth is real and contractable — bull.** Average ERCOT demand rose 6.1% in 2025, West Texas load rose 12.3%, and system cryptocurrency demand reached 4.6 GW [2025 ERCOT State of the Market Report](https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf). If high-credit data centers sign shaped long-term contracts at attractive returns, existing nuclear and gas sites become more valuable. The wildcard is whether the economics accrue to legacy ERCOT, Calpine, or unallocated commercial activity.

- **Renewable capture and battery cannibalization — bear/base.** Solar depresses midday prices; batteries arbitrage those lows and discharge during the evening ramp. EIA expects 37 GW of batteries by end-2027 [EIA January 2026 outlook](https://www.eia.gov/todayinEnergy/detail.php?id=67005). This may reduce both gas run hours and ancillary-service revenue. It also makes nuclear's flat output more exposed to low-price hours unless contracted.

- **Nuclear availability and PTC interaction — all cases.** South Texas Project is a scarce carbon-free asset, but a refueling extension or forced outage during a high-price period can create both lost generation and replacement-power cost. The federal nuclear production tax credit provides a price floor but phases down as gross receipts rise [data_package §0a, rows 88-101]. The bull cannot count both full high-market pricing and full PTC support.

- **Gas availability, heat rate, and firm fuel — bear/bull.** Flexible gas can capture evening and winter value, but pipeline constraints, fuel-price spikes, emissions limits, or equipment outages can reverse economics. Firm Fuel Supply Service and reliability products may provide revenue, but rules and procurement quantities remain subject to change. The bull assumes availability, not extraordinary gas-price exposure.

- **Retail load-shape mismatch — bear.** Fixed-price load can become short during extreme heat or cold. Customer attrition can leave excess hedges; customer growth can leave the portfolio short. Vistra and NRG's larger integrated retail books may offer superior diversification. `[DATA GAP: ERCOT segment customer count, churn, load shape, hedge ratio, and generation-to-load matching are not disclosed.]`

- **Calpine accounting leakage or double count — all cases.** Common commercial operations may create real synergies, but future segment disclosures could place benefits in Calpine or Other activities not allocated rather than legacy ERCOT. This appendix assigns none until disclosed. Synthesis must not add the same Texas synergy through both ERCOT and Calpine.

- **Antitrust and divestiture execution — bear/base.** DOJ's remedy removes Fusco and Gregory from the combined portfolio and establishes that withholding concerns are material. Delays, stranded commercial arrangements, or additional behavioral scrutiny could reduce optimization. Conversely, successful divestiture may lower concentration risk. The plants are not in this segment model, so proceeds or lost RNF must not be inserted here.

- **RTC+B and scarcity-price redesign — all cases.** ASDCs replaced ORDC, batteries are co-optimized, and real-time reserve awards are more efficient. The reform can reduce artificial costs while changing who captures reserve value. Early observations are not enough to set a stable terminal margin; a full-cycle monitor is required.

- **Transmission reconfiguration — bear/bull.** More transmission can unlock load and reduce curtailment, but it can also erase nodal scarcity. The Independent Market Monitor argues current load zones no longer reflect the grid's topology. A future zone redesign could change retail hedges, congestion revenue rights, and basis risk even if system prices are unchanged.

- **Weather and Winter Storm recurrence — bear.** FY2021's negative $0.825 billion RNF proves tail risk is not theoretical [2022 Form 10-K, Note 5](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm). Weatherization, hedging, and market reform reduce but do not eliminate fuel and load-shape exposure. The 36.0% terminal bear margin is not a stress-year trough; an individual year can be materially worse.

- **New dispatchable entry — bear/base.** NRG's 1.5 GW development program, Texas Energy Fund projects, and other gas additions can dilute scarcity rents. New generation may also be needed to serve demand and can validate the market. The key is timing relative to load. The base assumes neither a permanent shortage nor a glut.

- **Firming rules for new resources — bull/base.** NRG's Q1 2026 filing notes a PUCT firming rule for new generation resources with interconnection agreements on or after January 1, 2027 [NRG Q1 2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1013871/000101387126000012/nrg-20260331.htm). Requirements to acquire additional capacity during low-reserve hours may raise costs for new intermittent resources and increase the value of existing dispatchable assets. They can also subsidize new firming arrangements and create regulatory complexity.

- **Customer and contract quality — bull/bear.** Long-duration contracts can convert volatility into visible RNF, but prices, escalators, collateral, curtailment, credit, and change-in-law terms are confidential. The model does not assume attractive economics merely because a contract is long. A high-credit, well-shaped agreement is upside; a mispriced fixed-price obligation is downside.

Summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	$1.696B	RNF (Operating revenues net of Purchased power and fuel expenses)	36.0%	$0.610B	30%
Base	$2.175B	RNF (Operating revenues net of Purchased power and fuel expenses)	52.0%	$1.131B	55%
Bull	$2.511B	RNF (Operating revenues net of Purchased power and fuel expenses)	60.0%	$1.506B	15%

The probability mix is intentionally non-uniform. Base receives 55% because existing assets, retail integration, hedging, and Texas load growth support continued RNF, but margin normalization is more likely than another straight-line surge. Bear receives 30% because the Q1 revenue decline, renewables, storage, RTC+B, retail competition, and load-forecast slippage can weaken the portfolio even without another FY2021 event. Bull receives 15% because realizing both 6.0% revenue growth and a sustained 60.0% RNF margin requires favorable legacy-ERCOT contracting, load materialization, asset availability, and market shape simultaneously. The weighted terminal outcome is $2.081 billion revenue and $1.031 billion RNF; it is not a forecast substitute. Synthesis should preserve all three cases and avoid treating Calpine's Texas economics as part of this accounting segment.

Appendix S - Synthesis (Combined Earnings Model)

Constellation Energy Corporation — Synthesis (Combined Earnings Model)

This appendix consolidates the six reviewed segment forecasts mechanically, preserves their sealed common profit basis, and then forecasts every corporate, operating, below-line, tax, noncontrolling-interest, and share-count line separately. No segment appendix was rescaled, no bridge item was allocated into a segment, and no residual or plug was used. Dollar figures are USD billions unless stated otherwise. “TTM+5y” means exactly March 31, 2031, five calendar years after the March 31, 2026 TTM anchor.

1. Anchors and pre-model gates

Anchor	Controlling value
Today	2026-08-06
Fiscal year end	December 31
TTM end	2026-03-31
TTM quarters	Q2 FY2025 + Q3 FY2025 + Q4 FY2025 + Q1 FY2026
Latest completed FY	FY2025; historical tie-out only
Horizon	2031-03-31; exactly 5.0 calendar years after TTM end
Valuation price	USD 265.12 per common share; XNAS:CEG; raw exchange close
Quote session and expiry	Session 2026-08-05; actionable through 2026-08-07T09:02:30+08:00
Quote source hashes	Raw evidence `44e3a284e2ca433b925f1ffc6d23fd80562c922ed0ab46eb54731e4e5d5b51c9`; packet `662e9b2718cc428b746ebdc95096d2a69410d21a6216383bacd97338fb32999f`
Reporting and quote currencies	USD and USD; session-date FX is 1.0000 USD per USD
Security unit	Common share; no depositary receipt; financial shares per listed unit 1.0000
Split bridge	354M Q1 diluted weighted-average shares × split factor 1.0000 = 354M quote-basis diluted financial shares
Listed-unit bridge	Depositary ratio 1.0000 × share-class factor 1.0000 = 1.0000 financial share per listed unit; 354M ÷ 1.0000 = 354M listed-unit equivalents
Period-end ownership distinction	362M period-end common shares is the cover/balance ownership count and is not the EPS denominator
Statutory bridge	SHA-256 `227bdac4e38cca9b15f36fef332cef5fb35d00faab35013a0f6d4841dc02a0be`; validator valid; FY2025 and TTM zero residuals

At 2026-08-06T11:09:42+08:00 the strict quote-packet validator returned `QUOTE_PACKET_VALID` and reproduced the expected packet hash. The statutory validator returned `STATUTORY_BRIDGE_VALID` and the expected bridge hash. `gate_manifest.json` contains the durable DR verdict `STATUTORY BRIDGE VERIFIED — CLEARED FOR FORECASTING`, with DR status `cleared_for_wave_2` and no unresolved issues. The horizon check is mechanical: March 31, 2026 plus five calendar years is March 31, 2031.

The six post-review segment files were rehashed before modeling. Only these reviewed bytes supplied segment forecast values.

Reviewed segment file	Gate-manifest SHA-256	Recomputed status
`appendix_B_mid_atlantic.md`	`06f2871947a8690c739d72d579d9b2a084f48fcbd1785dcc51629e496836318c`	MATCH
`appendix_B_midwest.md`	`1510d192e5687b246e24ee98d7213b247d6b1da5313d2186e9e6562b40929f06`	MATCH
`appendix_B_new_york.md`	`21c2b12e7a65f7251bb30f12a85dfb557651dedfa812c5641007aa5ffa41405a`	MATCH
`appendix_B_ercot.md`	`7371e229e8b9e3fbf83af314280496bbc7b91f14718c2c18a081aaf53f7b80bb`	MATCH

Reviewed segment file	Gate-manifest SHA-256	Recomputed status
appendix_B_other_power_regions.md	010e24212e79e0d69215462f5fcc46ffe539c221b37f352e41a51361242ae05f	MATCH
appendix_B_calpine.md	44b52f72a38c8f61ceba1de784878d66c1368eacfb0c0c0173c1aef3770fbccc	MATCH

2. Segment-level forward assumptions

The exact common metric in every row is `RNF (Operating revenues net of Purchased power and fuel expenses)`. It is revenue less purchased power and fuel, not statutory operating income. TTM and terminal values below reproduce each reviewed appendix's Sections 8-10; they are not re-derived estimates.

Segment	Exact profit metric	TTM revenue	Bear TTM+5y rev	Base TTM+5y rev	Bull TTM+5y rev	Bear margin	Base margin	Bull margin
Mid-Atlantic; appendix Section 10	RNF (Operating revenues net of Purchased power and fuel expenses)	6.669	6.850	8.426	9.613	42.0%	52.0%	56.5%
Midwest; appendix Sections 8-10	RNF (Operating revenues net of Purchased power and fuel expenses)	6.132	5.828	7.603	9.006	50.0%	58.0%	63.0%
New York; appendix Sections 8-10	RNF (Operating revenues net of Purchased power and fuel expenses)	2.197	1.986	2.426	2.673	64.0%	72.0%	75.0%
ERCOT; appendix Sections 8-10	RNF (Operating revenues net of Purchased power and fuel expenses)	1.876	1.696	2.175	2.511	36.0%	52.0%	60.0%
Other Power Regions; appendix Sections 8-10	RNF (Operating revenues net of Purchased power and fuel expenses)	5.514	4.982	6.088	6.871	12.0%	17.0%	22.0%
Calpine; appendix Sections 8-10	RNF (Operating revenues net of Purchased power and fuel expenses)	2.395	8.500	10.900	13.000	35.0%	42.0%	48.0%

Terminal RNF reproduced from those same files is, respectively, Mid-Atlantic 2.877 / 4.381 / 5.431; Midwest 2.914 / 4.410 / 5.674; New York 1.271 / 1.747 / 2.005; ERCOT 0.610 / 1.131 / 1.506; Other Power Regions 0.598 / 1.035 / 1.512; and Calpine 2.975 / 4.578 / 6.240 for bear / base / bull.

Calpine needs special handling. Its reported TTM contains only 84 owned days. The reviewed appendix explicitly normalizes to 8.6 / 9.5 / 10.2 in the first forward year, then uses decision-relevant 2027-2031 organic CAGRs of negative 0.3% / positive 3.5% / positive 6.3%. The displayed five-year reported CAGRs of 28.8% / 35.4% / 40.3% are mathematical ownership effects, not organic growth assumptions. Nothing in this synthesis compounds the partial-period 2.395 or 1.126 naively as a recurring quarter.

3. Combined revenue build

The six reportable segments do not exhaust consolidated revenue: the sealed data package has an issuer-disclosed `Other activities not allocated` line. It was 5.084 in the TTM and contains commercial, corporate, unallocated, and acquisition-related activity. It is projected independently, not hidden as an elimination. The terminal bear / base / bull revenue paths are 3.500 / 5.800 / 7.500, with terminal RNF of 0.700 / 1.800 / 2.600. Bear normalizes acquisition/fair-value and low-spread activity sharply; base keeps the line close to its disclosed commercial scale and grows modestly; bull requires stronger contracted commercial margin. Corporate eliminations remain zero because no sealed input discloses a separate elimination.

Line	Bear	Base	Bull
Sum of six reportable-segment TTM+5y revenue	29.842	37.618	43.674
Other activities not allocated revenue	3.500	5.800	7.500
Corporate eliminations	0.000	0.000	0.000
Combined TTM+5y revenue	**33.342**	**43.418**	**51.174**
Implied reported TTM-to-TTM+5y CAGR over 5.0 years	2.23%	7.77%	11.37%

The reported CAGR uses consolidated TTM revenue of 29.867. It is not an organic descriptor because the TTM contains only 84 Calpine days. Base revenue after the first full-ownership year grows from 38.106 at March 31, 2027 to 43.418 at March 31, 2031, a more decision-relevant 3.32% four-year CAGR.

Base first-forward-year normalization	USD B
Reported consolidated TTM revenue	29.867
Less 84-day Calpine segment revenue	(2.395)
Add reviewed Calpine first-full-year base revenue	9.500
Ownership-normalized recent run-rate	36.972
Five legacy segment first-forward-year revenue	23.406
Calpine first-forward-year revenue	9.500
Other activities not allocated first-forward-year revenue	5.200
Base first-forward-year combined revenue	38.106
Difference versus ownership-normalized recent run-rate	3.07%

The 27.6% increase versus the unadjusted 29.867 TTM is a quantified ownership step, not evidence of 27.6% organic growth. The 9.500 Calpine figure is 8.7% below the reviewed appendix's 10.407 daily straight-line diagnostic, explicitly allowing for seasonality, hedge roll, remedy sales, and the six missing January days. Other activities not allocated rises only 2.3% from 5.084 to 5.200 because its mixed taxonomy prevents mechanical annualization. On this source-bound comparison basis, the first-forward-year model is within 10% of recent scale.

4. Combined operating income build

The forecast-driver ledger controls the non-segment bridge. `Other activities not allocated` is forecast as RNF. O&M is an independent fleet-capacity, outage, inflation, and Calpine-integration path. D&A is a PP&E and purchase-accounting path. Taxes other than income taxes are 2.50% / 2.35% / 2.25% of bear / base / bull revenue. Gain on asset sales is zero in every recurring case. No announced sale consideration is treated as operating income.

Line	Bear	Base	Bull
Sum of segment TTM+5y RNF	11.245	17.282	22.368
Other activities not allocated RNF	0.700	1.800	2.600
Consolidated TTM+5y RNF	11.945	19.082	24.968
Operating and maintenance	(10.000)	(9.600)	(9.400)
Depreciation and amortization	(2.600)	(2.500)	(2.600)
Taxes other than income taxes	(0.834)	(1.020)	(1.151)
Gain on sales of assets	0.000	0.000	0.000
Combined statutory TTM+5y operating income	**(1.489)**	**5.962**	**11.817**
Implied operating margin	(4.47%)	13.73%	23.09%

The apparent bear asymmetry is intentional. Lower revenue and RNF do not make nuclear, gas, geothermal, retail-platform, maintenance, labor, outage, and purchase-accounting costs disappear. Base O&M grows from the partial-ownership TTM 6.394 to 8.800 in the first full-ownership year and 9.600 by 2031. Bull O&M is lower than base despite higher activity because it requires availability and integration success; D&A is not reduced in bull and reaches 2.600. These are explicit scenario

judgments tied to the sealed driver categories, not algebraic residuals.

Case and bridge line	TTM	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31
Bear other activities revenue	5.084	4.400	4.000	3.800	3.600	3.500
Bear other activities RNF	1.340	0.900	0.820	0.760	0.720	0.700
Bear O&M expense	(6.394)	(9.000)	(9.300)	(9.600)	(9.800)	(10.000)
Bear D&A	(1.180)	(2.100)	(2.250)	(2.400)	(2.500)	(2.600)
Bear taxes other than income	(0.691)	(0.876)	(0.852)	(0.838)	(0.831)	(0.834)
Bear recurring gain on sales	0.014	0.000	0.000	0.000	0.000	0.000
Base other activities revenue	5.084	5.200	5.350	5.500	5.650	5.800
Base other activities RNF	1.340	1.500	1.580	1.650	1.730	1.800
Base O&M expense	(6.394)	(8.800)	(9.000)	(9.200)	(9.400)	(9.600)
Base D&A	(1.180)	(2.000)	(2.150)	(2.300)	(2.400)	(2.500)
Base taxes other than income	(0.691)	(0.895)	(0.929)	(0.963)	(0.994)	(1.020)
Base recurring gain on sales	0.014	0.000	0.000	0.000	0.000	0.000
Bull other activities revenue	5.084	5.800	6.200	6.600	7.000	7.500
Bull other activities RNF	1.340	1.700	1.900	2.100	2.350	2.600
Bull O&M expense	(6.394)	(8.600)	(8.800)	(9.000)	(9.200)	(9.400)
Bull D&A	(1.180)	(2.000)	(2.150)	(2.300)	(2.450)	(2.600)
Bull taxes other than income	(0.691)	(0.901)	(0.963)	(1.026)	(1.089)	(1.151)
Bull recurring gain on sales	0.014	0.000	0.000	0.000	0.000	0.000

Taxes other than income taxes are calculated directly from each year's combined revenue, not interpolated as an OI plug. For example, base 2031 is 43.418 × 2.35% = 1.020. Bear uses the upper historical ratio; bull uses the lower bound but bears greater absolute taxes as revenue scales. The discrete TTM gain of 0.014 is set to zero under every recurring scenario, consistent with the ledger.

5. Net income and EPS build

Interest is tied to the Q1 gross-debt anchor and deleveraging scenarios. Bear retains 22.466 of debt and a roughly 5.0% terminal cash cost; base deducts only the announced 3.400 deleveraging target, reaching 19.066; bull reaches 17.466 only by realizing the full 5.000 announced asset-sale scale. No proceeds are also added to cash or buybacks. `Other, net` is normalized far below the 1.136 TTM because NDT and other fair-value items are not extrapolated wholesale. The tax rate is 28.5% bear and the disclosed normalized 25.5% in base and bull. Noncontrolling interest remains an explicit negative line.

Line	Bear	Base	Bull
Combined TTM+5y OI	(1.489)	5.962	11.817
Interest expense, net	(1.123)	(0.800)	(0.699)
Other, net	0.250	0.550	0.750
Pre-tax income	(2.362)	5.712	11.868
Normalized tax rate	28.5%	25.5%	25.5%
Tax expense / benefit	0.673	(1.457)	(3.026)
Net income before NCI	(1.689)	4.255	8.842
Net income attributable to NCI	(0.010)	(0.008)	(0.006)
Net income attributable to common	**(1.699)**	**4.247**	**8.836**
Quote-basis diluted financial shares at TTM+5y, M	354.133	347.016	343.458

Line	Bear	Base	Bull
EPS USD per quote-basis financial share	(4.797)	12.240	25.726
Financial shares per listed unit	1.000	1.000	1.000
EPS USD per listed unit	(4.797)	12.240	25.726
FX USD per reporting USD	1.000	1.000	1.000
EPS in quote currency per listed unit	**USD (4.797)**	**USD 12.240**	**USD 25.726**

The mandatory bridge is explicit: `EPS_REPORTING_PER_QUOTE_BASIS_FINANCIAL_SHARE = NI_REPORTING ÷ QUOTE_BASIS_DILUTED_FINANCIAL_SHARES`; then `EPS_QUOTE_PER_LISTED_UNIT = reporting EPS × 1.000 financial share per listed unit × 1.000 USD/USD`. The base case is 4.24744B ÷ 347.016M = USD 12.2399 per quote-basis share and therefore USD 12.2399 per listed common share.

The below-line paths are independently specified as follows.

Case and below-line path	TTM	2027-03-31	2028-03-31	2029-03-31	2030-03-31	2031-03-31
Bear interest expense, net	(0.618)	(0.900)	(1.000)	(1.050)	(1.100)	(1.123)
Bear other, net	1.136	0.250	0.250	0.250	0.250	0.250
Bear normalized tax rate	30.8% observed	28.5%	28.5%	28.5%	28.5%	28.5%
Bear NCI	(0.006)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)
Base interest expense, net	(0.618)	(0.950)	(0.900)	(0.860)	(0.830)	(0.800)
Base other, net	1.136	0.450	0.500	0.550	0.550	0.550
Base normalized tax rate	30.8% observed	25.5%	25.5%	25.5%	25.5%	25.5%
Base NCI	(0.006)	(0.008)	(0.008)	(0.008)	(0.008)	(0.008)
Bull interest expense, net	(0.618)	(0.900)	(0.820)	(0.760)	(0.720)	(0.699)
Bull other, net	1.136	0.550	0.600	0.650	0.700	0.750
Bull normalized tax rate	30.8% observed	25.5%	25.5%	25.5%	25.5%	25.5%
Bull NCI	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)

5a. Return-method input bridge

The EPS/P-E method is fully reconciled. The EV/NOPAT alternative cannot control because the sealed input set does not provide decision-safe terminal paths for lease liabilities, preferred claims, minority balance-sheet claims, other senior claims, or separately valued non-operating assets. They are marked unavailable rather than plugged into net debt.

Terminal input	Bear	Base	Bull	Source-bound treatment
Statutory operating income	(1.489)	5.962	11.817	Section 4 mechanical bridge
Normalized cash tax rate	28.5%	25.5%	25.5%	Section 3a ledger; 25.5% disclosed normalized rate
Normalized NOPAT	(1.065)	4.442	8.804	OI × one minus normalized cash tax rate
Terminal cash	0.800	1.200	2.000	Explicit scenario from Q1 cash-only anchor 0.800; no sale-proceeds double count
Gross debt	22.466	19.066	17.466	Q1 22.466; base less announced 3.400 deleveraging; bull less full 5.000 sale scale
Lease liabilities	Unavailable	Unavailable	Unavailable	No terminal path in sealed decision inputs
Preferred equity	Unavailable	Unavailable	Unavailable	No terminal path or decision-safe zero in sealed inputs
Minority interest balance	Unavailable	Unavailable	Unavailable	NCI income line exists, but terminal balance claim is not supplied

Terminal input	Bear	Base	Bull	Source-bound treatment
Other senior claims	Unavailable	Unavailable	Unavailable	No residual claim plug permitted
Separately valued non-operating assets	Unavailable	Unavailable	Unavailable	NDT and other assets not separately valued in sealed inputs
Diluted listed-equivalent shares, M	354.133	347.016	343.458	Section 6; listed-unit factor 1.000

6. Share-count path

The forward denominator starts at 354M quote-basis Q1 diluted weighted-average financial shares. It does not start from the 362M period-end ownership count or the 323.359M day-weighted historical TTM denominator. The packet has no split, ADR, or class conversion. Historical post-spin buybacks were about 1.0B in 2023 and 2024, 0.4B in 2025, and management has authorized 5.0B. Bear uses 0.4B annually, base 0.8B, and bull 1.0B. Average repurchase price begins at the sole packet price and rises 3% annually. No second quote is introduced.

TTM SBC expense is unavailable because Q1 FY2026 did not disclose total quarterly SBC. The nearest reviewed disclosure is FY2025 SBC of 0.385B. Dividing that expense by USD 265.12 gives 1.452M shares, rounded to 1.450M annual issuance. This is a disclosed approximation, not an equity-compensation valuation model. As a cross-check, FY2025 diluted shares declined from 315M to 314M while 0.4B buybacks at the current-price proxy retire 1.509M and the SBC proxy issues 1.450M, implying negative 0.059M rather than negative 1.0M. The 0.941M difference is consistent with timing, cash settlement, price, and weighted-average effects; it is disclosed and not forced into the forecast as a plug.

Case / year	Starting shares, M	Buyback, USD B	Avg price, USD	Shares retired, M	SBC issuance, M	Ending shares, M
Bear 2027	354.000	0.400	265.120	1.509	1.450	353.941
Bear 2028	353.941	0.400	273.074	1.465	1.450	353.926
Bear 2029	353.926	0.400	281.266	1.422	1.450	353.954
Bear 2030	353.954	0.400	289.704	1.381	1.450	354.024
Bear 2031	354.024	0.400	298.395	1.341	1.450	354.133
Base 2027	354.000	0.800	265.120	3.018	1.450	352.432
Base 2028	352.432	0.800	273.074	2.930	1.450	350.953
Base 2029	350.953	0.800	281.266	2.844	1.450	349.559
Base 2030	349.559	0.800	289.704	2.761	1.450	348.247
Base 2031	348.247	0.800	298.395	2.681	1.450	347.016
Bull 2027	354.000	1.000	265.120	3.772	1.450	351.678
Bull 2028	351.678	1.000	273.074	3.662	1.450	349.466
Bull 2029	349.466	1.000	281.266	3.555	1.450	347.361
Bull 2030	347.361	1.000	289.704	3.452	1.450	345.359
Bull 2031	345.359	1.000	298.395	3.351	1.450	343.458

The arithmetic closes in every case. Base, for example, begins at 354.000M, retires 14.234M, issues 7.250M, and ends at 347.016M after unrounded calculations. Total base buybacks are 4.0B, below the 5.0B authorization; bull uses the full 5.0B and no more. Buyback cash is USD, the reporting currency, so no transaction-period FX conversion is required.

7. P/E 15 test

Case	EPS USD per listed unit	EPS × 15	Packet price per listed unit	Cushion	Pass?
Bear	(4.797)	(71.96)	265.12	(127.14%)	FAIL
Base	12.240	183.60	265.12	(30.75%)	FAIL
Bull	25.726	385.88	265.12	45.55%	PASS

Cushion equals $(\text{EPS} \times 15 - 265.12) \div 265.12$. The required EPS is 265.12 ÷ 15 = USD 17.6747 per listed unit. The confident base case, not the bull case, controls. Base is USD 5.4348 below the required EPS and its P/E-15 value is USD 81.52 below the packet price. Therefore the binary P/E 15 gate is **FAIL**, regardless of bull upside.

8. Reflexivity and historical anchor

The TTM revenue reconstruction ties exactly: six reportable segments sum to 24.783 and other activities not allocated contributes 5.084, producing consolidated 29.867. The statutory bridge also ties exactly: segment RNF 11.878 + corporate/unallocated RNF 1.340 – O&M 6.394 – D&A 1.180 – taxes other 0.691 + gain 0.014 = OI 4.967. The residual is zero, well inside the bridge's 0.001B tolerance and the 2% reflexivity limit.

FY2025 provides the independent historical sanity check: segment RNF 10.669 + other activities 0.183 – O&M 6.159 – D&A 0.985 – taxes other 0.622 = OI 3.086. Reportable-segment revenue 21.968 + other activities revenue 3.565 = consolidated revenue 25.533. The bridge files show zero segment, corporate, operating, pretax, and net-income residuals for FY2025 and the TTM. No forecast line repairs or reclassifies that history.

The historical denominator distinction is also preserved. Historical TTM EPS is 3.791B divided by the day-weighted 323.358904M quarterly diluted shares, or USD 11.7238. Forward per-share work starts from the latest disclosed Q1 diluted weighted-average 354M in the quote packet. The 362M period-end common count remains an ownership/control data point, not an EPS base.

9. Latest interim bridge reconciliation

NOT TRIGGERED — four non-overlapping standalone quarters used. The exact periods are Q2 FY2025 ended June 30, 2025; Q3 FY2025 ended September 30, 2025; Q4 FY2025 ended December 31, 2025; and Q1 FY2026 ended March 31, 2026. No cumulative six-month, nine-month, or YTD period overlaps a standalone quarter.

TTM metric	Q2 FY2025	Q3 FY2025	Q4 FY2025	Q1 FY2026	TTM sum
Revenue	6.101	6.570	6.074	11.122	29.867
Operating income	0.951	1.086	0.598	2.332	4.967
Pretax income	1.273	1.395	0.692	2.125	5.485
Common net income	0.839	0.930	0.432	1.590	3.791
Diluted weighted-average shares, M	314	313	313	354	323.358904 day-weighted

The day weighting is `(314 × 91 + 313 × 92 + 313 × 92 + 354 × 90) ÷ 365 = 323.358904M`; quarterly EPS is not summed. Q4 is the directly reported standalone quarter and also equals FY2025 less comparable nine months. This confirms like-for-like period and horizon integrity.

10. Sensitivity — which variable matters most

Each row holds every other base-case assumption fixed. Mid-Atlantic is the largest disclosed TTM segment by revenue. Midwest is the second-largest and largest RNF segment. EPS effects include the 25.5% normalized tax rate where operating profit changes.

Variable held against base	Down case	Base EPS	Up case	EPS change versus base
Mid-Atlantic revenue CAGR minus / plus 200 bps	11.376	12.240	13.172	(0.864) / +0.932
Midwest terminal RNF margin minus / plus 200 bps	11.912	12.240	12.565	(0.328) / +0.325
Terminal diluted shares minus / plus 5%	12.884 at minus 5%	12.240	11.656 at plus 5%	+0.644 / (0.584)
Tax rate minus / plus 300 bps	12.734 at 22.5%	12.240	11.747 at 28.5%	+0.494 / (0.493)

Mid-Atlantic growth is the largest tested operating swing, followed by the share denominator. Even the favorable Mid-Atlantic CAGR sensitivity produces only USD 13.172 EPS, still far below the USD 17.6747 gate. The verdict therefore does not depend on a small tax or margin modeling choice. A base-case pass would require a much broader combination of segment RNF, operating-cost control, and share retirement, not one ordinary sensitivity move.

11. Combined earnings summary

The consolidated probabilities are 30% bear, 55% base, and 15% bull. Base receives the highest weight because verified fleet reliability, contracts, and ownership normalization support the middle path. Bear is twice bull because management and moat

reviews are YELLOW, Calpine has only 84 owned days, debt is elevated, and remedy/integration/market-normalization risks can occur independently; bull requires simultaneous load conversion, strong contracts, availability, integration, and deleveraging. The weights are not uniform and sum to 100%.

Case	Revenue, USD B	OI, USD B	OI margin	NI, USD B	EPS USD per listed unit	Probability	EPS × 15	Versus USD 265.12
Bear	33.342	(1.489)	(4.47%)	(1.699)	(4.797)	30%	(71.96)	(127.14%)
Base	43.418	5.962	13.73%	4.247	12.240	55%	183.60	(30.75%)
Bull	51.174	11.817	23.09%	8.836	25.726	15%	385.88	45.55%
Probability-weighted EPS	N/A	N/A	N/A	N/A	9.152	100%	137.27	(48.22%)

Probability-weighted EPS is `30% × (4.797) + 55% × 12.240 + 15% × 25.726 = USD 9.152`. It is a scenario statistic, not a fourth earnings path and not a substitute for the confident base case.

Tie-out checks

- **PASS — Reported-financial and statutory-bridge tie-out.** TTM revenue is 24.783 segment revenue + 5.084 other activities = 29.867. TTM OI is 11.878 segment RNF + 1.340 corporate RNF – 6.394 O&M – 1.180 D&A – 0.691 taxes other + 0.014 gain = 4.967. FY2025 OI is 10.669 + 0.183 – 6.159 – 0.985 – 0.622 = 3.086. Both residuals are zero in `statutory_bridge.json` and `data_package.md` Sections 1, 2, and 3a; both are within the 0.001B packet tolerance and 2% reflexivity limit.

- **PASS — NI / shares / listed unit / FX equals EPS.** Bear: negative 1.69883B ÷ 354.133M × 1.000 × 1.000 = USD negative 4.7972. Base: 4.24744B ÷ 347.016M × 1.000 × 1.000 = USD 12.2399. Bull: 8.83566B ÷ 343.458M × 1.000 × 1.000 = USD 25.7256. Section 5 and `quote_packet.json` reproduce every factor.

- **PASS — Segment sum at horizon.** Six reportable segments plus the separately named corporate/unallocated revenue line equal combined revenue exactly: bear 29.842 + 3.500 = 33.342; base 37.618 + 5.800 = 43.418; bull 43.674 + 7.500 = 51.174. Combined revenue divided by the sum of all modeled revenue lines is 100.00% in each case. Section 3 names the non-segment gap; eliminations are zero.

- **PASS — Product-to-segment rollup.** Each reviewed Section 10 has one issuer-disclosed dollar product/economic line. Its product revenue equals segment revenue at 100.0% for all 18 segment-case rows. The six reviewed appendix Section 10 tables provide the check; no undisclosed plant, technology, or geography dollars are created.

- **PASS — Weighted margin check.** No segment has more than one disclosed additive product line. The conditional multi-product calculation is not triggered; the one-line revenue-weighted margin equals the displayed segment margin exactly in all six appendices. For example, base Midwest 7.603 × 58.0% = 4.410, and base Calpine 10.900 × 42.0% = 4.578.

- **PASS — Share count and security-unit path.** 354M financial-statement diluted shares × split factor 1.000 = 354M quote-basis diluted shares; 354M ÷ depositary factor 1.000 ÷ class factor 1.000 = 354M listed units. Base starts at 354.000M, retires 14.234M, issues 7.250M, and ends at 347.016M on unrounded values. Bear and bull close at 354.133M and 343.458M. `quote_packet.json` and Section 6 provide the full five-year arithmetic. The 362M period-end ownership count is never substituted.

- **PASS — Growth plausibility.** Base CAGRs of 4.787% Mid-Atlantic, 4.4% Midwest, 2.0% New York, 3.0% ERCOT, and 2.0% Other Power Regions are well below 1.2 times the reviewed historical or comparable trajectory ceilings. Calpine's reported 35.4% is acquisition ownership normalization; the reviewed appendix separately identifies 3.5% normalized organic growth from 2027-2031 and explicitly justifies its above-national-demand spread with selective contract wins, remedy-sale haircuts, and commercial scale. Reviewed Sections 6, 8, and 10 contain the comparisons and required justification.

- **PASS — Historical arithmetic at exactly five years.** Mid-Atlantic: 6.669 × 1.00536^5 = 6.850; × 1.04787^5 = 8.426; × 1.07586^5 = 9.613. Midwest: 6.132 × 0.98990^5 = 5.828; × 1.0440^5 = 7.603; × 1.0799^5 = 9.006. New York: 2.197 × 0.98^5 = 1.986; × 1.02^5 = 2.426; × 1.04^5 = 2.673. ERCOT: 1.876 × 0.98^5 = 1.696; × 1.03^5 = 2.175; × 1.06^5 = 2.511. Other Power Regions: 5.514 × 0.97990^5 = 4.982; × 1.02000^5 = 6.088; × 1.04499^5 = 6.871. Calpine's mathematical reported bridge is 2.395 × 1.28845^5 = 8.500; × 1.35409^5 = 10.900; × 1.40302^5 = 13.000, while the reviewed appendix correctly models the first year as ownership normalization and subsequent years organically. All terminal differences are below 1% and no row uses six years.

- **PASS — Recency anchor.** The raw TTM is not comparable because Calpine appears for only 84 days. The source-bound ownership-normalized recent run-rate is 29.867 − 2.395 + 9.500 = 36.972. Base first-forward-year combined revenue is 23.406 legacy segments + 9.500 Calpine + 5.200 corporate/unallocated = 38.106, only 3.07% above that recent normalized scale. `appendix_B_calpine.md` Section 8 quantifies the 9.500 normalization and its 8.7% haircut to the 10.407 daily diagnostic; Section 3 above shows the arithmetic.

- **PASS — Period and horizon integrity.** Four non-overlapping standalone quarters sum to TTM revenue 29.867, OI 4.967, pretax 5.485, and NI 3.791; the day-weighted share denominator is 323.358904M. Section 9 lists identical quarter boundaries. Forecast start 2026-03-31 and end 2031-03-31 differ by exactly five calendar years. Calpine's ownership step is labeled, every segment growth interval states its dates, and no FY2025 anchor or six-year span replaces the TTM.

- **PASS — Valuation, unit bridge, hashes, and probability arithmetic.** Exact-byte hashes recomputed to packet `662e9b2718cc428b746ebdc95096d2a69410d21a6216383bacd97338fb32999f` and statutory bridge `227bdac4e38cca9b15f36fef332cef5fb35d00faab35013a0f6d4841dc02a0be`; both strict validators passed. XNAS:CEG, raw-close basis, USD/USD 1.000, split 1.000, depositary 1.000, and class 1.000 all reproduce the unit bridge. EPS × 15 is negative 71.96 / 183.60 / 385.88; 30% + 55% + 15% = 100%; weighted EPS is 9.152. Cushions against the sole USD 265.12 packet price are negative 127.14% / negative 30.75% / positive 45.55%. Base controls and fails.

SYNTHESIS CLEARED — 11/11 TIE-OUTS PASSED. P/E 15 gate: FAIL — cushion (30.75%).

Appendix CS - Compounder Score

Constellation Energy Corporation - Compounder Score

Run: `pulse-cio-20260806T090230+0800` **Analysis date:** 2026-08-06 **Information cutoff:** 2026-08-06 09:02:30 SGT
Reporting currency: USD **Primary valuation method: P/E Trade execution authorized:** false

1. Executive Verdict

Compounder Score 43/100. Business Quality Score 39/80. 20% Return Underwriting/Stretch Score 4/20. Score-implied classification: Reject.

The evidence supports a valuable physical franchise, especially the nuclear fleet, but it does not support the economics or entry price required by this diagnostic. Constellation has scarce licensed nuclear sites, a demonstrably strong operating record, difficult-to-replicate interconnections, the Geysers geothermal resource, and the ability to contract with hyperscalers for 20 years. Those strengths are real. They coexist with a five-year median normalized ROIC of only 6.63%, an unusable acquisition-inclusive ROIIC history after the January 2026 Calpine close, volatile statutory cash conversion, $22.466 billion of gross debt, and a blended business whose gas, retail, regulatory, and commodity exposures weaken the pure nuclear moat.

The price is the decisive failure. The immutable packet price is $265.12 on 2026-08-05. TTM statutory diluted EPS is $11.723815, making the current statutory P/E 22.613799x. The audited base case produces only $12.2399 of statutory diluted EPS at 2031-03-31. At an independently supported 18.0x exit P/E, base terminal share value is $220.3182 and cumulative dividends are $10.4153006, producing a gross USD annualized shareholder return of negative 2.7401%. The probability-weighted gross return is negative 4.9481%, calculated from probability-weighted terminal wealth, not by averaging scenario IRRs. A 20% return at the same 18.0x base exit multiple would require $36.071561 of terminal EPS, a 25.2043% EPS CAGR from current statutory EPS, versus the audited base terminal EPS of $12.2399.

The mandatory CIO overlay is also adverse. Using the same P/E values and terminal wealth, a current USD/SGD anchor of 1.28068, 35 basis points each for entry and exit costs, 30% U.S. dividend withholding, and scenario exit FX of 1.15 / 1.24 / 1.34 SGD per USD, probability-weighted net-SGD return is negative 5.32%. The overall CIO status is **PASS**, meaning no portfolio action is supported. Missing holdings and factor exposure constrain portfolio-fit assessment and sizing only; they do not make the return rows or the CIO status null. This research does not rank CEG against POWR, prescribe a replacement, set size, or authorize a trade. On the security evidence alone, CEG has not earned the right to replace POWR.

2. Data Source Map

The stage rehashed the upstream artifacts before use. The controlling hashes include `quant_foundation.md` at `4E19E4D4BEF7938D48944FEA474D240840A62EFD03E9CD8AEF3D1D61A352ED63`, `data_package.md` at `5980ADD9E81B14BAADABE1BEE2175A010324FE4B0FEDE3BF81D43101C1EF54B3`, `appendix_management.md` at `CF98480C466806101C26E1479BDFDB2B62256642E679029C5810336A800D72E1`, `appendix_moat.md` at `0225198A76A1E8D56ECC8ACF857C529A8C891D23A3C83C52EE8A4583707DFAD9`, and `appendix_synthesis.md` at `F017B0800CFD670A55F1BE4E5C1F2BEF4BDFA485B57C57A2247A43136D1BD7B7`. The sealed quote packet hash is `662E9B2718CC428B746EBDC95096D2A69410D21A6216383BACD97338FB32999F`; the statutory bridge hash is `227BDAC4E38CCA9B15F36FEF332CEF5FB35D00FAAB35013A0F6D4841DC02A0BE`.

Input	Controlling source	Period / date	Use
Price, listing, current shares	`quote_packet.json`; QF/QFR	Price session 2026-08-05; Q1 2026 shares	$265.12, XNAS:CEG, 354M diluted listed-equivalent shares
Income statement and statutory EPS	`quant_foundation.md`; `statutory_bridge.json`	FY2021-FY2025 and TTM 2026-03-31	Historical quality, TTM EPS, reconciled P/E method
Balance sheet and debt	`data_package.md`; Q1 2026 10-Q	2026-03-31	$0.800B cash, $22.466B gross debt, $21.666B cash-only net debt
Cash flow, dividends, buybacks, SBC	QF P6; data package; 2025 10-K	FY2021-FY2025 and TTM	Conversion, dilution, capital allocation
Segment economics and runway	Six reviewed segment appendices	TTM through 2031-03-31	Revenue/RNF cases and competitive evidence
Management and allocation	`appendix_management.md`	Through cutoff	YELLOW gate; Calpine and incentive assessment

Input	Controlling source	Period / date	Use
Moat and 2046 durability	`appendix_moat.md`	Through 2046 test	YELLOW/YELLOW gates; physical moat and break conditions
Terminal operating cases	`appendix_synthesis.md`	2031-03-31	Revenue, OI, NI, EPS, shares, probabilities; 11/11 tie-outs
Historical P/E	Live FMP stable `ratios`	FY2021-FY2025	Profitable anchors 18.7992x FY2024 and 23.2849x FY2023; FY2025 47.7392x is distorted
Forward EPS valuation	Live FMP stable `analyst-estimates`	FY2026-FY2030	Packet-price P/Es of 22.5932x, 19.8814x, and 12.4313x on FY2026, FY2027, FY2030 averages
Dividend per share	Live FMP stable `dividends`	Declared 2026-04-28; record date 2026-05-15	$0.4265 quarterly; $1.706 annualized starting anchor; the later 2026-08-18 calendar row is excluded by the cutoff
USD/SGD	Live FMP stable FX EOD	2026-08-05	1.28068 SGD per USD current anchor

The four fresh CS pulls are archived under `raw/pulse-cio-20260806T090230+0800/cs/` and copied without overwrite to the investing warehouse. Their SHA-256 hashes are `F6F6AEEEE6409B3EF389143EA5DADF427236B2F9BB068A2713A96493CFC096F9` for ratios, `CD38D43BE1662E340586B721598428952997D96A239D1671D0C50D87DA681C3B` for estimates, `21B4C4776C5D3A341A000D6AAAAB165F6682182A2BE9A6CB1AE233D7FB5BC0BC` for dividends, and `3F14E8FEECA34C3AAC54D2DC9CC45A0115D032518E77A74910F30F57C43FD1A0` for USD/SGD.

3. Key Financial and Quality Metrics

Constellation has only five comparable post-separation annual observations. That limitation is material. A ten-year standalone history does not exist, and Calpine contributes only 84 owned days to the TTM. The score therefore avoids false precision and marks metrics null where the required denominator cannot be credibly reconstructed.

Metric	Result	Formula / interpretation
Revenue CAGR, FY2021-FY2025	6.77%	`(25.533 / 19.649)^(1/4) - 1`
Five-year median normalized ROIC	6.63%	Median of -1.35%, 2.09%, 6.63%, 16.90%, 12.00%
3-year ROIIC	Insufficient evidence	Endpoint proxy is 127.48%, but collateral, cash, and capital-base swings make it non-decision-safe
Acquisition-inclusive ROIIC	Insufficient evidence	Calpine closed 2026-01-07; no seasoned post-close NOPAT/reinvestment period
TTM normalized NOPAT	$3.700415B	$4.967B statutory OI times 74.5%
TTM statutory FCF conversion	30.73%	$1.137B FCF / $3.700415B normalized NOPAT
Five-year cumulative FCF conversion	-265.23%	Cumulative statutory FCF / cumulative normalized NOPAT; collateral/working capital distort it but cannot be ignored
FY2025 CFO / net income	182.71%	$4.237B / $2.319B
FY2025 FCF / net income	55.54%	$1.288B / $2.319B
FY2021-FY2025 diluted share CAGR	-0.99%	326.7M to 314M; Calpine then lifted Q1 2026 diluted shares to 354M
FY2025 SBC / revenue	1.51%	$0.385B / $25.533B
FY2025 SBC / FCF	29.89%	$0.385B / $1.288B
TTM FCF yield	1.21%	$1.137B / $93.85248B quote-basis diluted market cap
Current annualized dividend yield	0.64%	$1.706 / $265.12
TTM net buyback yield	0.43%	$0.400B / $93.85248B
Gross debt / cash-only net debt	$22.466B / $21.666B	Q1 2026, contextual P/E inputs only
Current statutory P/E	22.6138x	$265.12 / $11.723815 TTM statutory diluted EPS

The five-year cumulative cash conversion is poor, but it should not be read as a literal steady-state economics estimate. FY2023 and FY2024 operating cash flow included very large collateral and working-capital movements. The opposite mistake would be to discard the statutory history and substitute management's adjusted FCF-before-growth target. This score gives

credit for the FY2025 recovery and management's $8.4B 2026-2027 FCF-before-growth outlook, but it caps cash-conversion points until reported cash after maintenance, integration, working capital, and tax consistently supports earnings.

Current market capitalization is approximately $93.85248B using 354M quote-basis diluted shares. A contextual enterprise-value approximation is $115.51848B after adding $21.666B cash-only net debt. It excludes an unavailable current lease path and is not used to value equity. On TTM normalized NOPAT, that incomplete-context EV/NOPAT is about 31.22x. No EV-derived amount controls a scenario, score, reverse-return hurdle, or CIO return.

4. Rubric Scorecard

Category	Score	Maximum	Evidence-based conclusion
Incremental Returns on Capital	7	25	Median ROIC is below 10%; ROIIC is not credibly measurable; fleet unit economics are strong but cash conversion is volatile
Reinvestment Runway	12	20	Data-center load, uprates, Crane, contracts, and Calpine create runway; execution and return proof are incomplete
Durability of Moat	10	15	Nuclear licenses, operations, geothermal, and interconnections are strong; blended pricing power is limited
Accounting and Financial Quality	5	10	Reconciliations and controls are clean; cash conversion and leverage are not
Capital Allocation	5	10	Historical buybacks show some discipline; Calpine economics and deleveraging remain unseasoned
Price and 20% Return Underwriting	4	20	Conservative multiples do not rescue base or weighted returns; only bull clears the CIO return band
Business Quality Score	**39/80**	**80**	**Promising assets, but insufficient high-ROIIC and post-Calpine proof**
20% Return Underwriting/Stretch Score	**4/20**	**20**	**Current price fails the return hurdle by a wide margin**
Compounder Score	**43/100**	**100**	**Reject under this diagnostic rubric**

Subscore detail is 1/5, 0/8, 1/3, 2/3, 1/3, and 2/3 for Category 1; 4/5, 2/5, 3/4, 2/3, 1/2, and 0/1 for Category 2; 4/4, 1/3, 2/3, 1/2, 1/2, and 1/1 for Category 3; 2/2, 0/2, 1/2, 0/2, 1/1, and 1/1 for Category 4; 1/2, 0/2, 1/2, 1/2, 1/1, and 1/1 for Category 5; and 0/6, 3/4, 0/3, 0/3, 0/2, and 1/2 for Category 6.

5. ROIIC and Reinvestment Analysis

Standard ROIC is informative but incomplete for this merchant-power and nuclear operator. Nuclear assets require large, lumpy maintenance, fuel, outage, relicensing, uprate, and decommissioning-related spending. Commodity hedges and collateral cause large working-capital movements. Calpine also changed the capital base abruptly through $21.835B of closing-date consideration and assumed debt. The score therefore uses normalized statutory NOPAT over average invested capital as the most reproducible historical measure, while refusing to treat a mechanical endpoint ROIIC as economic truth.

Normalized NOPAT rose from $0.368775B in FY2022 to $2.29907B in FY2025. Dividing each endpoint NOPAT by the disclosed ROIC implies average invested capital of roughly $17.64B and $19.16B. The mechanical change-in-NOPAT over change-in-capital proxy is about 127.48%. That number is not awarded ROIIC credit because it does not equal cumulative reinvestment under the rubric, omits a reliable acquisition-inclusive path, and is unusually sensitive to collateral/cash movements and a favorable power/policy cycle. A spectacular-looking ROIIC without a credible denominator would be precisely the accounting artifact this score is designed to reject.

Unit-economics evidence is better. The nuclear fleet sustained capacity factors of 94.4%-94.7% in FY2023-FY2025, with Midwest and New York RNF margins consistently strong. Existing-site uprates and long-duration contracts can add output without greenfield siting and interconnection economics. Yet RNF is revenue less purchased power and fuel, not segment operating income. O&M, D&A, taxes other than income taxes, below-line financing, and corporate costs still matter. The business receives partial credit for fleet execution, not high-ROIIC credit by implication.

The decisive future test is acquisition-inclusive. Management must show that Calpine contributes at least the promised approximately $2 of EPS and more than $2B of annual FCF without recurring integration exclusions, while $3.4B of deleveraging is completed by end-2027. Until then, reinvestment at scale is a claim supported by strategy and initial operations, not a seasoned return record.

6. Runway Analysis

The runway is meaningful. Microsoft supports the approximately 835 MW Crane restart through a 20-year PPA. Meta contracted Clinton's 1,121 MW output beginning in June 2027 and a planned 30 MW uprate for 20 years. CyrusOne contracted 380 MW at Freestone and an exclusive second 380 MW phase. Management reported more than 10,000 MW under long-term deals. The combined company owns scarce sites, grid connections, powered land, nuclear operating expertise, and a national customer platform at a time when data-center and reliability demand are rising.

However, runway is not the same as attractive reinvestment. Contract prices are confidential. Crane requires regulatory and execution success. Hyperscaler loads can be delayed. FERC, PJM, NRC, state policy, and antitrust remedies influence the rent shareholders retain. Calpine's first CEG-owned disclosure covers only 84 days. The base model's ownership-normalized revenue grows only 3.32% annually from the first full-ownership year through 2031, despite the reported TTM-to-horizon revenue CAGR of 7.77%. That distinction matters: much of the apparent growth is acquisition ownership normalization, not organic compounding.

The score gives 12/20 because the addressable opportunity and brownfield playbook are real, but there is not yet proof that the combined company can deploy capital repeatedly without ROIC collapse. The earliest upgrades would be three years of post-close statutory ROIC above 15%, disclosed contract economics or cash outcomes consistent with double-digit unlevered returns, and deleveraging that does not crowd out fleet reliability.

7. Moat Analysis

The moat gate and 2046 test are both YELLOW. The clearest advantage is the combination of licensed nuclear sites, specialized outage and fuel operations, NRC credibility, interconnections, trained workforce, and high-trust ability to make 20-year commitments. The Geysers adds a scarce geothermal asset, and Calpine's powered sites add optionality. These assets cannot be replicated by software or a new retail entrant.

Pricing power is narrower. It is visible in contract tenor and complexity, not disclosed unit pricing. Commodity MWh, standard retail supply, gas generation, and some commercial services remain competitive. ERCOT economics can swing sharply, Other Power Regions has weak margins, and regulation is a barrier and a rent allocator at the same time. The company also has no meaningful network effect or formal IP monopoly. The moat is strong at the nuclear and site level but only moderate in the blended portfolio.

The 2046 company is plausible: relicensed nuclear plants, geothermal, flexible generation, storage, large customer contracts, and fewer but more contracted gas assets. High returns through 2046 are not yet proven. Nuclear PTC support expires before the test date, contracts require renewal, some licenses require subsequent renewal, and gas/retail economics face decarbonization and automation pressure. A roughly one-third erosion case in the moat appendix prevents a PASS.

8. Accounting and Capital Allocation Analysis

Accounting controls and reconciliations are strengths. FY2025 and TTM statutory bridges have zero residuals, QF passed 8/8 reconciliation checks, synthesis passed 11/11 tie-outs, and the management review found no restatement, material weakness, related-party concern, or dual-class issue. SBC was 1.51% of FY2025 revenue. This is noticeable, especially after rising from $47M in FY2021 to $385M in FY2025, but not chronic software-style dilution.

Financial quality is weaker. TTM FCF conversion is only 30.73% of normalized NOPAT, while five-year statutory conversion is negative because of collateral and working-capital swings. Gross debt jumped to $22.466B after Calpine, and a downgrade below investment grade could require about $3B of incremental collateral. These are not accounting failures; they are economic reasons cash available to shareholders may diverge from earnings.

Capital allocation receives only 5/10. Post-spin repurchases had some price sensitivity, and management reduced buybacks during transaction preparation. The $5B authorization is not automatically treated as value creation. Issuing about 50M fixed shares for Calpine, then repurchasing shares above $280, creates a demanding per-share proof burden. The acquisition may ultimately be attractive, but one reported quarter cannot establish that. Incentives also lack an explicit ROIC measure and lean on adjusted FCF and relative TSR.

9. 20% Return Underwriting

Method selection and valuation evidence

`PRIMARY_VALUATION_METHOD = PE` is frozen across bear, base, bull, probability weighting, reverse-return, max-buy-price, and net-SGD. Statutory diluted EPS is reconciled. EV/NOPAT cannot control because terminal lease liabilities, preferred claims, minority balance-sheet claims, other senior claims, and distinct non-operating assets are unavailable. Under P/E, debt and cash are contextual inputs only. No cash is added and no debt is subtracted after EPS times P/E.

The current P/E is 22.613799x on TTM statutory EPS. Live FMP annual ratios show profitable year-end P/Es of 23.284861x in FY2023 and 18.799160x in FY2024; FY2025's 47.739189x is given little weight because statutory EPS fell to $7.40 while the stock had rerated. At the packet price, live FMP average analyst EPS implies 22.593227x on FY2026, 19.881381x on FY2027, and 12.431290x on FY2030. These are adjusted-consensus context, not replacements for audited statutory terminal EPS.

The bear's negative $4.7972 terminal statutory EPS makes a positive P/E economically not meaningful. The operative loss-case multiple is therefore 0.0x, applying a limited-liability equity floor of zero rather than publishing a negative share value. Base uses 18.0x, below current P/E and close to FY2024's profitable 18.8x. Bull uses 20.0x, below current P/E but near FY2027 forward and inside the profitable historical range. No scenario uses the 15x entry gate as its automatic exit multiple.

Distributions begin from the live $0.4265 quarterly dividend, or $1.706 annualized. Bear is a clearly labeled zero-distribution suspension diagnostic, consistent with negative terminal statutory earnings. Base applies management's stated 10% annual dividend-growth policy, producing $10.4153006 cumulative distributions. Bull uses 12% annual growth, a conditional sensitivity requiring the bull cash path, producing $10.83795759616. Buybacks affect the synthesis share-count denominator and are not also added as distributions.

Case	Probability	Terminal EPS	Exit P/E	Terminal equity value / share	Cumulative distributions / share	Terminal wealth / share	Gross USD IRR
Bear	30%	$(4.7972)	0.0x loss-case floor	$0.0000	$0.0000	$0.0000	-100.00%
Base	55%	$12.2399	18.0x	$220.3182	$10.4153006	$230.7335006	-2.74%
Bull	15%	$25.7256	20.0x	$514.5120	$10.83795759616	$525.34995759616	14.66%
Probability-weighted	100%	N/A	Same-method wealth CAGR	N/A	N/A	$205.705918969424	-4.95%

The probability-weighted return equals `($205.705918969424 / $265.12)^(1/5) - 1`. It is not 30% times bear IRR plus 55% times base IRR plus 15% times bull IRR. The exact model horizon is 2026-03-31 to 2031-03-31, five calendar years. The price observation is the 2026-08-05 packet close; the five-year model exponent is retained to remain consistent with the audited TTM+5 horizon.

Gross debt and cash-only net debt are contextual P/E inputs: bear $22.466B / $21.666B, base $19.066B / $17.866B, and bull $17.466B / $15.466B. They influence statutory interest expense and scenario EPS. They are not equity-value adjustments. The double-count check passes: buybacks affect shares only, dividends enter wealth once, and cash/debt enter statutory EPS through financing rather than being added after EPS times P/E.

Bear-case operating and return bridge

Values are USD except share count in millions. These tables show gross local-currency underwriting; net-SGD adjustments appear separately under CIO actionability.

Bear case	Start (TTM 2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	$29.867B	$33.342B	2.23%	Calpine ownership step is offset by lower RNF, remedy and market normalization
Operating margin	16.63%	(4.47%)	(21.10) pp	Fixed fleet O&M and D&A do not fall with revenue/RNF
Operating earnings	$4.967B	$(1.489)B	N/M sign crossover	Statutory operating income from the audited bridge
Diluted share count	354.000M	354.133M	0.01%	$0.4B annual buybacks roughly offset 1.45M annual SBC issuance

Bear case	Start (TTM 2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
EPS	$11.723815	$(4.7972)	N/M sign crossover	Statutory diluted EPS after retained debt and weak operating earnings
Valuation	22.61x current	0.0x operative	Loss-case floor	Negative EPS cannot support a positive earnings-capitalized equity value
Share value	$265.12	$0.00	(100.00%)	Limited-liability floor; no cash/debt adjustment after P/E
Annual dividend	$1.706	$0.000	Suspended	Zero-distribution diagnostic under sustained statutory loss
Dividend yield	0.64%	N/M	N/M	Terminal share value and annual dividend are both zero
Five-year dividends	-	$0.000	cumulative	Explicit zero-distribution diagnostic
Total ending value	$265.12	$0.000	-100.00% gross local IRR	Terminal share value plus distributions

Base-case operating and return bridge

Base case	Start (TTM 2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	$29.867B	$43.418B	7.77%	Ownership normalization plus 3.32% growth from first full-ownership year
Operating margin	16.63%	13.73%	(2.90) pp	Full Calpine O&M/D&A and conservative unallocated RNF path
Operating earnings	$4.967B	$5.962B	3.72%	Statutory operating income, not RNF or adjusted EBITDA
Diluted share count	354.000M	347.016M	(0.40%)	$0.8B annual buybacks net of annual SBC issuance
EPS	$11.723815	$12.2399	0.87%	$4.24744B common NI divided by audited terminal shares
Valuation	22.61x current	18.0x exit	(4.61)x	Below current and near FY2024's profitable 18.80x anchor
Share value	$265.12	$220.3182	(3.63%)	$12.2399 EPS times 18.0x; no net-debt adjustment
Annual dividend	$1.706	$2.4977546	10.00%	Management's stated 10% annual dividend-growth policy
Dividend yield	0.64%	1.13%	+0.49 pp	Annual dividend divided by endpoint share value
Five-year dividends	-	$10.4153006	cumulative	Five annual payments grown at 10%
Total ending value	$265.12	$230.7335006	-2.74% gross local IRR	Share value plus cumulative distributions

Bull-case operating and return bridge

Bull case	Start (TTM 2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Revenue	$29.867B	$51.174B	11.37%	Strong contracts, load conversion, integration, and Calpine growth
Operating margin	16.63%	23.09%	+6.46 pp	Availability, RNF, and synergies outperform while D&A is not cut
Operating earnings	$4.967B	$11.817B	18.93%	Audited statutory operating-income bridge

Bull case	Start (TTM 2026-03-31; price 2026-08-05)	Horizon (2031-03-31)	CAGR / change	Justification
Diluted share count	354.000M	343.458M	(0.60%)	Full $5B authorization spread across five years, net of SBC
EPS	$11.723815	$25.7256	17.02%	$8.83566B common NI divided by terminal diluted shares
Valuation	22.61x current	20.0x exit	(2.61)x	Below current; requires quality and growth but not multiple expansion
Share value	$265.12	$514.5120	14.18%	$25.7256 EPS times 20.0x; no net-debt adjustment
Annual dividend	$1.706	$2.68442402816	12.00%	Conditional bull cash sensitivity above the 10% stated policy
Dividend yield	0.64%	0.52%	(0.12) pp	Annual dividend divided by terminal share value
Five-year dividends	-	$10.83795759616	cumulative	Five annual payments grown at 12%
Total ending value	$265.12	$525.34995759616	14.66% gross local IRR	Share value plus cumulative distributions

Reverse-return and max-buy-price diagnostic

At a 20% annual return for five years, required terminal wealth is $659.7033984 per share. After subtracting the base distribution path of $10.4153006, required terminal equity value is $649.2880978. At the frozen base 18.0x P/E, required statutory EPS is $36.07156099. That requires 25.204286% annual EPS growth from TTM statutory EPS, compared with the audited base terminal EPS of only $12.2399. The method-matched maximum purchase price is $92.726619 at the base terminal wealth and 20% hurdle. The current $265.12 price is about 2.86 times that diagnostic.

CIO actionability

The current FX anchor is 1.28068 SGD per USD on 2026-08-05 from the live FMP stable EOD FX pull. Net-SGD entry wealth is `265.12 x 1.28068 x 1.0035 = SGD 340.7222501856`. Each scenario uses the same P/E terminal share value as the gross model. Sale proceeds incur 35 basis points of exit cost; dividends incur a conservative 30% U.S. withholding assumption. The exit FX scenarios are 1.15 / 1.24 / 1.34 SGD per USD for bear / base / bull, explicitly anchored around current spot. No investor tax residency, broker, or account-specific treaty benefit is assumed.

Case	Probability	Exit USD/SGD	Net terminal wealth, SGD	Net-SGD IRR	CIO interpretation
Bear	30%	1.15	SGD 0.000000	-100.00%	Permanent-loss diagnostic; below intervention and target bands
Base	55%	1.24	SGD 281.2788679328	-3.76%	Below 10%-15% target even before portfolio fit
Bull	15%	1.34	SGD 697.1990229452	15.40%	Clears target band, but receives only 15% probability
Probability-weighted	100%	Scenario-weighted	SGD 259.2832308048	-5.32%	CAGR of probability-weighted net terminal wealth

Overall CIO status: PASS. The probability-weighted and base net-SGD returns fail the target. Bear loss is far beyond the 8% intervention and 12% hard-review levels. Portfolio holdings, concentration, sector/factor exposure, liquidity needs, and the exact POWR exposure were not provided, so portfolio fit is unavailable and sizing ceiling is null. That does not change the security-return conclusion. Proposed allocation is zero for this diagnostic, but no size or trade is authorized. `trade_execution_authorized=false`.

10. Hard Veto Checklist

Hard veto	Status	Finding
ROIIC below cost of capital with no path	Insufficient evidence	Credible acquisition-inclusive ROIIC cannot yet be calculated
High ROIC is an invested-capital artifact	Pass	Reported ROIC is not high; the score rejects the inflated endpoint proxy

Hard veto	Status	Finding
Growth requires external financing	Watch	Calpine materially increased debt and short-term borrowing
Share count rises without per-share value	Watch	Acquisition dilution may create value, but proof is not seasoned
Large acquisitions lack return disclosure	Watch	Calpine targets are adjusted and contract returns are confidential
FCF structurally lags earnings	Watch	Statutory conversion is weak; collateral effects are material but recurring
Regulation, cyclicality, or leverage can permanently impair equity	Fail	Bear statutory EPS is negative and terminal P/E equity value is zero
20% return requires terminal multiple expansion	Fail	Base requires about 53.05x on audited terminal EPS, or far higher EPS
Flawless execution is needed at today's price	Fail	Base loses money despite successful integration/deleveraging assumptions
Moat cannot be explained	Pass	Licensed nuclear operations, sites, interconnections, and high-trust contracts are clear
Accounting/governance impairs trust	Pass	Reconciliations, controls, and governance are clean
Balance-sheet risk can wipe out equity	Watch	Investment-grade liquidity exists, but debt/collateral risk is material

11. Final Decision

The evidence does not support purchase at $265.12 under this rubric. Constellation may become a high-quality compounder if Calpine integration, deleveraging, statutory cash conversion, and contract returns become visible. Today, the business-quality evidence is too mixed and the price requires too much. A watch trigger would be several combined-company years of above-15% statutory ROIC, clean cash conversion, completed deleveraging, and a price approaching the method-matched $92.73 max-buy diagnostic or a materially higher audited EPS base.

Compounder Score note: Compounder Score 43/100; real physical advantages are outweighed by unproven ROIIC, leverage, cash-conversion volatility, and inadequate returns at the current price. **Business Quality Score note:** Business Quality Score 39/80; the nuclear core is strong, but post-Calpine economics, blended pricing power, and 2046 high-return durability remain YELLOW. **20% Return UW Score note:** 20% Return Underwriting/Stretch Score 4/20; base gross USD IRR is -2.74%, weighted gross is -4.95%, and the same-method weighted net-SGD IRR is -5.32%.

The score-implied classification is **Reject**. The CIO status is **PASS**. CEG is not established as a replacement for POWR by this security-level research. No ranking, sizing, replacement instruction, or trade execution is authorized.

12. Machine-Readable JSON

The complete full-precision artifact is `compounder_score.json`. Its controlling summary is:


```
{
  "primary_valuation_method": "PE",
  "total_score": 43,
  "business_quality_score": 39,
  "valuation_underwriting_score": 4,
  "classification": "Reject",
  "gross_probability_weighted_irr": -0.049480875253108736,
  "net_sgd_probability_weighted_irr": -0.05316394586158801,
  "cio_status": "PASS",
  "trade_execution_authorized": false,
  "valuation_method_consistent_across_scenarios": true,
  "net_sgd_uses_same_primary_method": true,
  "double_count_check_passed": true
}
```

Appendix CSA - Scoring Audit

Constellation Energy Corporation - Scoring Audit

Analysis date: 2026-08-06 **Information cutoff:** 2026-08-06 09:02:30 SGT **Price:** USD 265.12 at the 2026-08-05 completed close **TTM / horizon:** 2026-03-31 / 2031-03-31; exactly 5.0 years **Audited primary valuation method:** P/E **Confidence:** Medium

1. Original vs Audited Scores

Item	Original	Audited	Notes
Business Quality Score / 80	39/80	38/80	ROIIC trend received one unsupported point despite 3-year, 5-year, and acquisition-inclusive ROIIC being unavailable
Valuation / 20% Return UW Score / 20	4/20	1/20	The 3/4 exit-multiple score conflicts with the rubric: the 20% case needs about 53.05x, a major expansion from both 22.61x current and 18.0x base
Total Score / 100	43/100	39/100	Four points removed; score arithmetic then reconciles exactly
Classification	Reject	Reject	Audited total is below 70 and the base, bear, and probability-weighted return tests fail

The original score reconstructed cleanly as `39 + 4 = 43`. Its category totals were 7, 12, 10, 5, 5, and 4. The audited category totals are 6, 12, 10, 5, 5, and 1, which sum to Business Quality `6 + 12 + 10 + 5 + 5 = 38` and Total Score `38 + 1 = 39`.

The original security return outputs were bear -100.00%, base -2.7401416%, bull 14.6571763%, and probability-weighted gross USD -4.9480875%, with weights of 30%, 55%, and 15%. The maximum buy price for a 20% IRR was USD 92.726619. All of those return figures reproduce and are preserved. The audit changes the score attached to the evidence, not the audited scenario arithmetic.

2. Score Reductions and Reasons

Rubric item	Original	Audited	Evidence status	Audit decision
1A Normalized ROIC is high	1/5	1/5	Partly supported	Five-year median normalized ROIC is 6.63%, which falls exactly in the rubric's positive-but-below-10% band. Lease and goodwill variants are missing, so no additional credit is available.
1B ROIIC is high	0/8	0/8	Missing data	Correctly zero. The 127.48% endpoint proxy is not cumulative-reinvestment ROIIC and is properly rejected.
1C ROIIC is not deteriorating	1/3	0/3	Unsupported	A trend cannot be established when neither 3-year nor 5-year ROIIC is calculated. This score is reduced because the claimed direction has no valid series.
1D Unit economics support returns	2/3	2/3	Partly supported	94.4%-94.7% nuclear capacity factors and strong Midwest/New York RNF support partial credit, but RNF is not operating income and contract returns are confidential.

Rubric item	Original	Audited	Evidence status	Audit decision
1E Cash conversion is real	1/3	1/3	Partly supported	FY2025 recovered, but TTM FCF/NOPAT is only 30.73% and five-year cumulative statutory conversion is -265.23%. Partial credit is already conservative.
1F ROIC is not an artifact	2/3	2/3	Partly supported	The normalized NOPAT/average-capital formula is reproducible and does not manufacture a high score. Missing lease and goodwill sensitivity prevents full credit.
2A Large market opportunity	4/5	4/5	Supported with limits	Official 20-year contracts, more than 10,000 MW under long-term deals, uprates, powered land, and load growth support the opportunity. Confidential pricing blocks full credit.
2B Proven reinvestment at scale	2/5	2/5	Partly supported	Fleet stewardship and brownfield projects provide some proof, but Calpine has only 84 owned days and no acquisition-inclusive return record.
2C Organic growth opportunity	3/4	3/4	Supported with limits	Crane, Clinton, uprates, and site/interconnection optionality are concrete. Regulatory milestones and confidential economics justify the one-point haircut.
2D Repeatable expansion playbook	2/3	2/3	Partly supported	Several contract/site examples support repetition, but completed cash-return evidence is not yet broad enough for full credit.
2E Market structure supports growth	1/2	1/2	Partly supported	Scarce interconnections and reliability demand help, while FERC/PJM/ERCOT intervention and rapid new supply cap the score.
2F Growth avoids ROIC collapse	0/1	0/1	Missing data	Correctly zero because post-Calpine acquisition-inclusive ROIC has not been demonstrated.
3A Clear source of advantage	4/4	4/4	Supported	Licensed nuclear sites, operating capability, workforce, interconnections, and the Geysers are specific and difficult to replicate.
3B Pricing power	1/3	1/3	Partly supported	Tenor and complexity are observable; unit pricing, escalation, churn, and fleet-wide realized pricing are not.
3C Competitive evidence	2/3	2/3	Supported with limits	Capacity-factor outperformance and contract wins are evidence; gas, retail, and merchant regions remain contestable.
3D Customer stickiness	1/2	1/2	Partly supported	Long-duration contracts create switching costs once operational, but they cover a minority of the blend and retail retention data are absent.
3E Resilience through stress	1/2	1/2	Partly supported	Nuclear operations are resilient, but historical cash collateral swings, merchant volatility, and leverage make full credit untenable.

Rubric item	Original	Audited	Evidence status	Audit decision
3F Low disruption risk	1/1	1/1	Supported	AI cannot replicate licensed physical generation and interconnection assets; the moat analysis separately captures retail commoditization risk.
4A Clean revenue and earnings quality	2/2	2/2	Supported	QF passed 8/8, statutory bridges have zero residual, and synthesis passed 11/11 tie-outs.
4B Cash flow supports earnings	0/2	0/2	Calculation adverse	Correctly zero after the multi-year statutory cash-conversion test.
4C Conservative SBC and dilution	1/2	1/2	Partly supported	SBC was 1.51% of revenue and 29.89% of FY2025 FCF; the forward model explicitly includes SBC issuance and share-count paths.
4D Balance-sheet strength	0/2	0/2	Calculation adverse	Correctly zero given USD 22.466B gross debt, USD 21.666B cash-only net debt, and collateral sensitivity.
4E Transparent disclosures	1/1	1/1	Supported with gaps	Statutory and operating disclosure is strong, although contract prices and project returns remain confidential.
4F No governance/accounting red flags	1/1	1/1	Supported	No restatement, material weakness, related-party concern, dual-class structure, or control issue was identified.
5A Rational reinvestment priority	1/2	1/2	Partly supported	Deleveraging, fleet investment, and contracts are coherent, but acquisition return proof is incomplete.
5B Acquisition discipline	0/2	0/2	Missing outcome evidence	Correctly zero. Calpine is material and acquisition-inclusive ROIIC is unavailable.
5C Buyback discipline	1/2	1/2	Partly supported	Post-spin repurchases showed some price sensitivity, but repurchases above USD 280 create a demanding proof burden.
5D Incentive alignment	1/2	1/2	Partly supported	FCF and relative TSR are better than scale-only pay, but there is no explicit ROIC metric and adjusted FCF exclusions are material.
5E Owner mentality	1/1	1/1	Supported with limits	Direct CEO ownership, an ownership policy, and price-aware repurchase history support one point, though unvested awards count toward policy.
5F Evidence from past decisions	1/1	1/1	Supported with limits	Nuclear operating performance and prior capital returns are observable; the zero acquisition-discipline score separately captures Calpine uncertainty.
6A Base IRR at least 20%	0/6	0/6	Calculation adverse	Base gross USD IRR is -2.74%, far below 10%, so zero is mandatory.
6B Conservative exit multiple	3/4	0/4	Rubric error	The rubric awards 4 only if a below-current multiple still clears 20%. It does not. Hitting 20% with base EPS needs about 53.05x, a major expansion, which maps to zero.

Rubric item	Original	Audited	Evidence status	Audit decision
6C Bear case acceptable	0/3	0/3	Calculation adverse	Bear shareholder wealth is zero and IRR is -100%.
6D Reverse hurdle beatable	0/3	0/3	Calculation adverse	Required terminal EPS is USD 36.071561 versus base USD 12.2399; required EPS CAGR is 25.20% versus base 0.87%.
6E Multiple does not price perfection	0/2	0/2	Calculation adverse	Current price is 2.86 times the same-method max-buy diagnostic and base value is below entry price.
6F Cash returns help	1/2	1/2	Supported	Dividends add USD 10.4153 in base and are counted once; they help modestly but do not rescue the hurdle.

The biggest score reduction is 6B. A below-current exit multiple can be conservative as a valuation assumption, but it cannot earn the rubric's high score when it produces a negative base return. The explicit 20% bridge requires a 53.0468x terminal P/E on base EPS, versus 22.6138x current and 18.0x modeled base. That is major expansion, not a conservative hurdle-clearing exit.

3. Unsupported Claims

- The original 1C point is unsupported. No valid 3-year or 5-year ROIIC series exists, so “not deteriorating” cannot be scored.
- The original 6B score is unsupported by the rubric threshold. An 18.0x exit is lower than today's multiple, but it fails the required return by a wide margin.
- The dividend amount is valid, but the cited `2026-08-18` FMP row is after the information cutoff and has no declaration date. The audit rejects that row as the source anchor. The same USD 0.4265 quarterly amount was already declared on 2026-04-28 with a 2026-05-15 record date in the same raw FMP file. That prior completed declaration controls without changing any dividend or return arithmetic.
- “Adjusted ROIC” is not fully demonstrated. The source package calculates normalized NOPAT over debt plus equity less cash, but it does not publish the required lease-inclusive and goodwill-excluding series. The low 1A score remains defensible; higher credit would not be.

4. Calculation Errors

The return arithmetic itself does not break. Independent recomputation produced the following:

Check	Independent result	Published result	Verdict
TTM normalized NOPAT	USD 4.967B x 74.5% = USD 3.700415B	USD 3.700415B	Pass
FY2025 normalized NOPAT	USD 3.086B x 74.5% = USD 2.299070B	USD 2.299070B	Pass
FY2025 ROIC	USD 2.299070B / USD 19.159B = 12.00%	12.00%	Pass
TTM FCF conversion	USD 1.137B / USD 3.700415B = 30.73%	30.73%	Pass
Current P/E	USD 265.12 / USD 11.723815 = 22.6138x	22.6138x	Pass
Base terminal wealth	USD 12.2399 x 18 + USD 10.4153006 = USD 230.7335006	USD 230.7335006	Pass
Base gross IRR	`(230.7335006 / 265.12)^(1/5) - 1` = -2.7401%	-2.7401%	Pass
Weighted terminal wealth	30% x 0 + 55% x 230.7335006 + 15% x 525.3499576 = USD 205.7059190	USD 205.7059190	Pass
Weighted gross IRR	`(205.7059190 / 265.12)^(1/5) - 1` = -4.9481%	-4.9481%	Pass
Required EPS at 20%	`(265.12 x 1.2^5 - 10.4153006) / 18` = USD 36.0715610	USD 36.0715610	Pass

Check	Independent result	Published result	Verdict
Max buy price at 20%	`230.7335006 / 1.2^5` = USD 92.7266190	USD 92.7266190	Pass

The scoring calculation breaks only at the interpretation of 6B, where the facts support 0/4 rather than 3/4.

5. Missing Data

The most important missing evidence is a seasoned, acquisition-inclusive reinvestment record after Calpine. Three-year ROIIC, five-year ROIIC, acquisition-inclusive ROIIC, and a reliable reinvestment-rate series are unavailable. Lease-inclusive ROIC and explicit including/excluding-goodwill variants are also absent. CEG has only five comparable post-separation annual observations, and Calpine contributes only 84 owned days to the TTM.

Other important gaps are terminal lease liabilities and senior-claim paths, combined-company full-cycle net debt/EBITDA, contract prices and project-level returns, retail retention/churn economics, and actual portfolio context. The first group correctly prevents EV/NOPAT from controlling; the last constrains portfolio fit and sizing, not the security IRRs.

6. Hard-Veto and Threshold Test Audit

All eight “Investable now” threshold tests fail: total below 80, Business Quality below 65, valuation below 15, ROIIC plus runway below 35, base IRR below 20%, bear IRR below 8%-10%, hard vetoes present, and the 20% case requiring major multiple expansion. The original `does_not_require_multiple_expansion=false` is correct even though the modeled base exit multiple is lower than current; the relevant test is whether the 20% case can work without expansion. It cannot.

Hard vetoes 7, 8, and 9 remain. Regulation/cyclicality/leverage can permanently impair equity in the audited bear; the 20% case needs either much higher earnings or a roughly 53.05x terminal P/E; and today's price requires substantially better than the audited base path. These vetoes are not needed to force the classification because 39/100 is independently below the Reject threshold.

7. Final 20% Hurdle Pass/Fail

FAIL. Base gross USD IRR is -2.74%, probability-weighted gross USD IRR is -4.95%, and probability-weighted net-SGD IRR is -5.32%. Only the 15%-probability bull reaches a positive mid-teens return, and even that does not reach 20%.

The frozen P/E method is consistent across bear, base, bull, probability weighting, reverse return, max buy price, and net-SGD. EPS times P/E receives no second cash/debt adjustment. Buybacks enter through diluted share count only, and dividends enter terminal wealth once. Net-SGD uses the same terminal P/E equity values; it applies 35 bp entry/exit costs, 30% dividend withholding, and scenario FX. Independent recomputation reproduces net-SGD wealth of SGD 0.0000 / 281.2788679 / 697.1990229 and probability-weighted net wealth of SGD 259.2832308, yielding -5.3164%. Method consistency and the double-count check pass.

8. Dream Business / Dream Investment Classification

Neither. CEG owns dream-business assets in its nuclear fleet and selected sites, but the combined company has not demonstrated the high, repeatable acquisition-inclusive ROIIC and cash conversion required to call the whole enterprise a dream business. It is not a dream investment at USD 265.12 because the base and probability-weighted returns are negative and the same-method 20% max-buy diagnostic is only USD 92.73.

The single biggest reason CEG does not qualify is the gap between price and supported earnings: at an 18.0x exit P/E, 20% requires USD 36.07 of terminal EPS, almost three times the audited base USD 12.24.

9. Stage 7 Scorecard Notes

- **Compounder Score note:** Compounder Score 39/100; scarce physical assets do not offset missing ROIIC proof and a price that fails the return hurdle.
- **Business Quality Score note:** Business Quality Score 38/80; the nuclear core is strong, but combined-company ROIIC, cash conversion, leverage, and Calpine outcomes remain unproven.
- **20% Return UW Score note:** 20% Return Underwriting/Stretch Score 1/20; base gross USD IRR is -2.74%, weighted gross is -4.95%, and weighted net-SGD is -5.32%.

10. Auditor JSON

The companion `compounder_score_audit.json` is the controlling full-precision artifact. Its compact result is:


```
{
  "audited_business_quality_score": 38,
  "audited_valuation_underwriting_score": 1,
  "audited_total_score": 39,
  "audited_classification": "Reject",
  "final_20pct_hurdle_pass": false,
  "audited_probability_weighted_gross_local_irr_pct": -4.948087525310874,
  "probability_weighted_irr_method": "CAGR_OF_PROBABILITY_WEIGHTED_TERMINAL_WEALTH",
  "audited_primary_valuation_method": "PE",
  "valuation_method_consistent_across_scenarios": true,
  "net_sgd_uses_same_primary_method": true,
  "double_count_check_passed": true,
  "dream_business_investment_classification": "neither"
}
```

Appendix RT - Red Team

Constellation Energy Corporation — Red Team

Analysis date: 2026-08-06 **Information cutoff:** 2026-08-06 09:02:30 SGT **TTM anchor / horizon:** 2026-03-31 / 2031-03-31, exactly five years **Starting price:** USD 265.12 at the 2026-08-05 completed close

This red team starts from the proposition that the model is giving Constellation credit too early for an acquisition whose economics have been observed for only 84 owned days. The nuclear fleet is real, but scarce physical assets do not make every dollar of Calpine, retail, trading, purchased-power activity, or “other activities not allocated” a durable high-return franchise. The burden of proof is especially high because the audited base return is already negative. At this price, the investor does not merely need the operating thesis to survive; the investor needs results materially better than the synthesis base case.

1. The most fragile assumption

The weakest assumption is **Calpine’s base terminal RNF margin of 42.0% on USD 10.9 billion of 2031 revenue**, producing USD 4.578 billion of RNF. It is the largest single modeled acquisition contribution, yet its anchor is a 47.0% RNF margin from the 84-day period after the January 7, 2026 close. There is no full-year history under Constellation ownership, no disclosed product split, no regional split, no customer-retention series, no hedge ratio, and no asset-level margin for the plants being sold. The appendix calls the five-point normalization haircut conservative; the red team calls it untestable.

The acquisition-period observation can be flattered by seasonality, hedge marks, purchase-accounting classification, favorable weather, or the timing of customer and fuel settlements. It also precedes a complete integration cycle for trading, billing, retail, fuel, credit, outage, and risk systems. Mandatory remedy sales add another problem: investors do not know whether the divested 4.4 GW carries above- or below-average RNF. A sale can reduce leverage while simultaneously removing the assets that made the observed margin look attractive. The synthesis cannot resolve that without asset-level disclosure.

The arithmetic consequence is material. If terminal Calpine revenue remains USD 10.9 billion but RNF margin is **37% rather than 42%**, terminal RNF falls by USD 545 million. Holding the rest of the synthesis constant and applying the 25.5% normalized tax rate reduces common earnings by about USD 406 million and EPS by approximately **USD 1.17**, from USD 12.24 to roughly **USD 11.07** on 347.016 million shares. That is a 9.6% EPS cut from one five-point margin miss. It widens the existing gap to the USD 17.67 P/E-15 requirement and makes the 20% return hurdle still more remote.

The first place this assumption should be rejected is not revenue. It is RNF conversion. Constellation can report high Calpine revenue while gas basis, fixed-price retail load, replacement power, congestion, customer churn, and hedge roll consume the spread. Revenue growth is therefore capable of creating false comfort. The acquisition thesis needs full-year RNF and cash conversion, not gross megawatt-hours or contract announcements.

2. The most-likely-to-be-optimistic Stage 5 number

The single synthesis number most likely to be revised down is **USD 5.962 billion of base-case statutory operating income in 2031**, equivalent to a 13.73% operating margin. It is not obviously aggressive in isolation. It is aggressive because too many unseasoned lines must work together to produce it: USD 19.082 billion of consolidated RNF, including USD 4.578 billion from Calpine and USD 1.800 billion from opaque unallocated activity; O&M held to USD 9.600 billion; D&A of USD 2.500 billion; and no recurring gain on sale.

The most questionable component after Calpine is “other activities not allocated.” Its TTM revenue of USD 5.084 billion and RNF of USD 1.340 billion mix commercial, corporate, unallocated, and acquisition-related activity. The synthesis raises its RNF to USD 1.800 billion by 2031 even though its taxonomy prevents a clean historical or economic decomposition. This is precisely where acquisition accounting, commercial optimization, internal transfer economics, and true corporate cost can blur. Treating it as an independently compounding profit source risks capitalizing a classification bucket.

A simple adverse bridge shows the vulnerability. Combine the five-point Calpine miss above with unallocated RNF remaining at USD 1.340 billion instead of rising to USD 1.800 billion. Operating income falls by roughly USD 1.005 billion to **USD 4.957 billion**, before any integration-cost, D&A, or O&M miss. At the modeled 25.5% tax rate, the EPS impact is about USD 2.16, taking base EPS near **USD 10.08**. The synthesis passed its arithmetic tie-outs, but arithmetic integrity does not validate the economic content of opaque inputs.

3. The strongest bear case, stated in its strongest form

Constellation paid a full price for Calpine near the top of an electricity-demand narrative, added substantial debt and 50 million shares, and is now asking investors to value an 84-day acquisition observation as the start of a durable high-margin platform. Over the next six to eight quarters, solar, storage, transmission, market redesign, asset remedies, customer competition, and hedge roll expose the thermal and retail spread while nuclear support formulas offset part of commodity upside. Calpine and ERCOT RNF disappoint, unallocated profit proves less durable than modeled, and deleveraging competes with maintenance, growth capex, dividends, collateral, and buybacks. The observable validation is rolling-four-quarter Calpine RNF below USD 3.5 billion: at that point the acquisition's base economics and the company's promised cash-conversion path are broken, not merely delayed.

This is not a thesis that power demand disappears. It is a thesis that **load growth accrues to customers, networks, new entrants, and capital spending before it accrues to Constellation shareholders**. PJM and ERCOT can need more power while regulators cap scarcity rents, interconnection costs rise, customers negotiate the value of their scale, and new gas, renewable, storage, transmission, and demand-response supply arrive. A megawatt shortage is not the same thing as high incremental ROIC. The report's own audited five-year median normalized ROIC is only 6.63%, TTM FCF/NOPAT conversion is 30.73%, and five-year cumulative statutory conversion is negative. The market is paying for a quality transition that the cash record does not yet demonstrate.

4. Cross-examination of management commentary

"Calpine will add $2 in EPS and $2 billion of free cash flow before growth starting next year."

Joe Dominguez made this statement on the Q2 FY2025 call on August 7, 2025, before Constellation owned Calpine. It is a transaction-underwriting claim, not an observed result. The governed package has only 84 owned days, no acquisition-inclusive ROIIC, and no full-year cash bridge. Q1 statutory operating cash flow was USD 425 million against USD 1.275 billion of capex, producing negative USD 850 million of quarterly FCF. Seasonality and transaction timing matter, but they do not excuse the absence of proof.

If this promise is wrong, the first evidence will be a gap between Calpine RNF and consolidated cash generation: full-year RNF may look acceptable while working capital, collateral, integration, maintenance, cash tax, and interest consume the promised cash. The correct test is not adjusted EPS accretion. It is rolling cash generation after maintenance needs and without recurring "integration" exclusions.

"At least $2 billion of annual incremental free cash flow."

Shane Smith repeated the acquisition cash claim on the Q4 FY2025 call on March 31, 2026. Repetition does not add evidence. Constellation also identified USD 3.9 billion of growth projects, USD 3.4 billion of deleveraging, 10% annual dividend growth, and a USD 5 billion repurchase authorization. Those uses compete for the same cash. Gross debt stood at USD 22.466 billion and cash-only net debt at USD 21.666 billion at March 31. A below-investment-grade downgrade could require roughly USD 3 billion of additional collateral.

If the claim is overstated, the first sign will be slower debt reduction or capital returns funded despite weak statutory conversion. Management can preserve an adjusted FCF target by classifying expenditures as growth, integration, or transaction-related. The red-team test is end-2027 gross debt and cash conversion, not the label attached to capex.

"The '28-'29 period rising to $11.5 billion to $13 billion."

Dominguez gave this longer-range FCF range on May 11, 2026. The range asks investors to accept a large step-up before there is one full owned year of Calpine, while project returns, contract prices, maintenance capital, and acquisition-inclusive returns remain confidential. Management's claimed minimum 10% unlevered growth-project return is also not a Gideon-quality reinvestment rate, and it sits below the framework's aspiration for durable 20%-plus capital compounding.

The earliest contradiction would be rising adjusted EPS accompanied by weak operating cash flow after working capital and maintenance. A second would be asset-sale proceeds doing the work that operating conversion was supposed to do. Selling assets to meet a deleveraging promise may protect creditors; it does not prove the acquired enterprise earns the projected return.

5. Stage 5 tie-out reverification

The recency anchor is mechanically sound: Q2 FY2025, Q3 FY2025, Q4 FY2025, and Q1 FY2026 are four non-overlapping quarters ending March 31, 2026. The problem is trend quality, not period overlap. Mid-Atlantic Q1 revenue grew 10.9%, yet RNF margin fell to **44.0%** from 57.6% in Q4. Midwest Q1 revenue grew 23.4%, yet RNF margin fell to **49.3%** from 58.8%; the segment appendix notes that USD 328 million of revenue growth produced only USD 4 million of incremental RNF. ERCOT Q1 revenue declined 7.0% and RNF margin eased to 56.5%. Other Power Regions revenue fell 4.4%. These prints warn that gross growth is already a poor proxy for spread growth.

The synthesis does not extrapolate the latest quarterly troughs, which is reasonable if they are temporary. It becomes optimistic if they are early evidence of support roll-off, procurement-heavy load, unfavorable hedge timing, or mix dilution. Base Midwest terminal margin of 58% assumes a recovery from 49.3%; base Mid-Atlantic reaches 52% from 44%; and Calpine settles at 42% without a full-year comparator. Three major margin normalizations must cooperate.

The share-count arithmetic also ties, but the financing priority is questionable. Base retires 14.234 million shares through USD 4.0 billion of repurchases while issuing 7.250 million through SBC, ending at 347.016 million shares. That buyback cadence competes with USD 3.4 billion of announced deleveraging, USD 3.9 billion of growth projects, maintenance, integration, and dividends. The package's TTM FCF conversion of 30.73% and negative Q1 FCF do not support treating buybacks as automatic. A 5% higher terminal denominator cuts EPS by USD 0.58; not fatal alone, but another subtraction from a base already failing valuation.

No segment CAGR violates an obvious peer-deceleration rule; the regional revenue paths are generally restrained. The deeper problem is that revenue CAGRs are not the decisive variable. Mid-Atlantic base revenue CAGR of 4.8% is the largest tested operating sensitivity, but the economic exposure lies in RNF conversion, corporate/unallocated classification, O&M, and cash conversion. The model is conservative on top-line rates and still can be optimistic on shareholder economics.

6. Score-derived 20% return claim most likely to be wrong

The audited score already says the 20% case **does not clear**, and the red team agrees. There is no plausible "one assumption" that rescues it. At USD 265.12, base terminal EPS of USD 12.2399 and an 18.0x exit P/E produce terminal wealth of USD 230.73 including dividends and a gross USD IRR of **negative 2.74%**. Probability-weighted gross IRR is **negative 4.95%**; probability-weighted net-SGD IRR is **negative 5.32%**. Even the 15%-probability bull reaches only 14.66% gross.

To earn 20% at the same 18.0x method, terminal EPS must reach **USD 36.07**, almost three times the audited base. Holding base EPS instead would require an exit P/E of **53.05x**, versus 22.61x current. The same-method maximum buy price is USD 92.73. Therefore the return failure is not caused by a debatable dividend assumption, 300 basis points of tax, 5% of shares, or 200 basis points of one segment's growth. It is a price-versus-supported-earnings failure.

What would have to change is not a score adjustment. Constellation would need acquisition-inclusive ROIIC and cash conversion far above the historical evidence, multiple contract and uprate projects at attractive disclosed economics, materially faster earnings growth, and no offsetting increase in required capital. Until then, any 20% narrative depends on bull-case operating outcomes plus an exit valuation the audit explicitly rejects.

7. The signal that forces an exit

The forced-exit signal is **rolling-four-quarter Calpine RNF below USD 3.5 billion by the first complete four-quarter ownership window, and again at the next quarterly update if management attributes the miss solely to timing**. The measurement should use the issuer's exact RNF basis and include any Calpine economics moved into "other activities not allocated" only through a disclosed, reconcilable reclassification; management should not be allowed to hide deterioration by changing segment taxonomy.

USD 3.5 billion is 14% below the modeled first-full-year base RNF of USD 4.085 billion and close to a bear conversion of the USD 8.6 billion normalization. Falling below it would mean the 84-day 47% margin was not a durable starting point, asset remedies or hedge roll removed more economics than expected, or integration and customer/fuel mismatch impaired the portfolio. Because Calpine is tied to the debt, share issuance, collateral exposure, and cash promises, this is not a normal quarterly miss. It invalidates the capital-allocation judgment underwriting the combined company.

If the company does not disclose a clean four-quarter Calpine RNF series, that opacity is itself adverse: calculate Calpine plus clearly identified acquisition-related unallocated RNF and require a statutory reconciliation. The exit rule should not be waived because system load is growing, adjusted EPS guidance is maintained, or asset sales reduce debt.

8. Conviction at the end of red team

Thesis does NOT survive. The break is the combination of an unseasoned Calpine margin assumption, opaque unallocated profit, poor demonstrated cash conversion, elevated acquisition debt, and a price that delivers negative base and probability-weighted returns even when the synthesis assumptions are met. The narrative should be rewritten around a simpler conclusion: Constellation owns exceptional nuclear assets, but the post-Calpine enterprise has not yet proven that its expanded capital base can earn high incremental returns, and USD 265.12 already demands more than the audited operating model supports.

This is not a claim that Constellation is a weak operator or that electricity demand is fictional. It is a claim that the security fails the asymmetry test. The downside includes leverage, collateral, regulatory rent reallocation, spread compression, outages, and integration; the upside requires several opaque profit pools to mature together. The P/E-15 gate fails in base, the audited 20% score is 1/20, and the same-method max-buy diagnostic is nearly two-thirds below the market price. The correct posture is PASS, with reconsideration only after full-year Calpine RNF and cash conversion are demonstrated, deleveraging is completed without sacrificing fleet reliability, and the entry price offers a return that does not require bull-case economics.

Appendix D - Data Package (raw historicals)

Constellation Energy Corporation (CEG) — Production ER2 Data Package

Run: `pulse-cio-20260806T090230+0800` **Information cutoff:** 2026-08-06 09:02:30 SGT **Reporting currency and scale:** USD millions unless stated otherwise **Fiscal year:** December 31 **Latest reported quarter permitted at the cutoff:** Q1 FY2026 ended 2026-03-31 **TTM:** Q2 FY2025 + Q3 FY2025 + Q4 FY2025 + Q1 FY2026, ending 2026-03-31 **Five-year horizon:** 2031-03-31, exactly five calendar years after the TTM end **Excluded evidence:** Q2 FY2026 results, which were scheduled after the cutoff, are a refresh trigger only.

This package is the downstream historical source for the CEG ER2. Quantitative financial-statement values were refreshed live from FMP stable endpoints and checked against live SEC filings. Official filings control where FMP differs. In particular, official Q3/Q4 FY2025 quarterly allocations, regional revenue, RNF, cash-only balances, and common-share bases override FMP. No local data-warehouse file was used as analytical evidence. Fresh FMP pulls are archived under `raw/pulse-cio-20260806T090230+0800/d/` and were copied without overwrite to the investing warehouse.

The issuer's exact segment performance metric is **RNF (Operating revenues net of Purchased power and fuel expenses)**. RNF is not statutory operating income. The QFR-sealed statutory bridge is reproduced without changing any label, sign, classification, or number.

0a. Industry classification and disclosure inventory

Classification, source set, and search inventory

CEG is a U.S. domestic merchant power, nuclear generation, retail energy, and—after the January 7, 2026 Calpine acquisition—natural-gas/geothermal generation company. It reports under U.S. GAAP through Forms 10-K and 10-Q. FMP segment/product data are **thin and classification-mixed**: the live annual product endpoint has only FY2023-FY2025 regional data and reports FY2025 New York revenue at $2,389 million versus the official $2,190 million. The official five-region Note 5 table, expanded to six current segments with Calpine in Q1 FY2026, controls.

Live official sources checked in this run include the [2025 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000032/ceg-20251231.htm), [2024 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827525000023/ceg-20241231.htm), [2023 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827524000014/ceg-20231231.htm), [2022 Form 10-K](https://www.sec.gov/Archives/edgar/data/1868275/000186827523000014/ceg-20221231.htm), Q2 and Q3 FY2025 Forms 10-Q, the FY2025 earnings exhibit, the [Q1 FY2026 Form 10-Q](https://www.sec.gov/Archives/edgar/data/1868275/000186827526000067/ceg-20260331.htm), the last four live FMP transcripts, CEG earnings releases, and official announcements for Calpine, Microsoft, Meta, and CyrusOne.

Search terms and official table names checked were: `Net Generation Capacity`, `sources of electric supply`, `Nuclear Generation`, `capacity factor`, `refueling outage days`, `non-refueling outage days`, `EFOF`, `dispatch match rate`, `renewable energy capture`, `RNF`, `Operating revenues net of Purchased power and fuel expenses`, `average day-ahead around-the-clock reference price`, `capacity prices`, `ZEC`, `CMC`, `nuclear PTC`, `realized economic hedges`, `expected generation hedged`, `merchant sales plan`, `retail load`, `long-term contract`, `PPA`, `data center`, `Calpine`, `free cash flow before growth`, `delever`, and `capital expenditures`.

Completeness matrix

Dataset / table family	Official source searched	Search terms or table names	Years available	Included?	If excluded, why	Downstream relevance
Segment revenue and RNF	2022-2025 10-Ks; 2025 Q2/Q3 and 2026 Q1 10-Qs	Segment Information; RNF	FY2021-FY2025; Q2'25-Q1'26	Yes	None	Segment forecasts and statutory bridge
Fleet capacity and output	2022-2025 10-Ks; Q1'26 10-Q	Net Generation Capacity; sources of electric supply	FY2022-FY2025; Q1'26	Yes	FY2021 capacity is a pre-spin/ownership boundary	Capacity, utilization, capex
Nuclear operations	2022-2025 10-Ks and quarterly releases	Capacity factor; generation; outage days	FY2021-FY2025; Q1'26	Yes	None	Reliability and margin durability

Dataset / table family	Official source searched	Search terms or table names	Years available	Included?	If excluded, why	Downstream relevance
Regional energy/capacity reference prices	2022-2025 10-Ks	Average day-ahead reference; capacity prices	FY2021-FY2025	Yes	These are references, not realized prices	RNF scenario drivers
Realized prices by region	10-K MD&A and segment notes	Realized price; settlement price	Not disclosed as a clean series	No	True non-disclosure; references and realized hedge bridges are disclosed instead	Limits direct price-volume decomposition
Hedge coverage and contracts	10-K risk sections; transcripts; PPA releases	Expected generation hedged; ratable plan; long-term deals	FY2022 baseline; current qualitative	Yes	Later filings emphasize PTC sensitivity instead of coverage percentages	Cash-flow visibility
Calpine generation economics	Q1'26 10-Q; transcripts; acquisition filings	Calpine revenue, RNF, supply, EFOF, debt	Q1 FY2026	Yes	Only 84 days consolidated; no clean CEG-owned annual history yet	Current segment base
Free cash flow, debt, shares	FMP stable; 2025 10-K; Q1'26 10-Q	OCF; capex; debt; merger consideration; shares	FY2021-FY2025; Q1'26	Yes	None	Deleveraging and per-share model
Data-center contracts	Microsoft, Meta, CyrusOne releases; transcripts	PPA; data center; co-location	2024-Q1'26	Yes	Contract prices are confidential	Contracted-load optionality
Reserve / resource tables	Annual reports	Reserves; resource life	N/A	No	Not applicable to a power generator purchasing fuel	Not a mining model

Historical operating KPI series

KPI family	Granularity	FY2021	FY2022	FY2023	FY2024	FY2025	Latest interim	Source
Nuclear capacity factor	Fleet at ownership; excludes non-operated plants per issuer definition	94.5%	94.8%	94.4%	94.6%	94.7%	92.3% Q1'26	2022 and 2025 10-Ks; Q1'26 release
Nuclear output	Owned output incl. Salem and later STP, TWh	173.0	173.4	174	182	183	44.666 Q1'26	2022-2025 10-Ks; Q1'26 release
Nuclear share of total electric supply	Company supply mix	65%	64%	65%	67%	68%	N/D quarterly	2022-2025 10-Ks
Average refueling outage duration	Operated units, days	22	21	21	19	22	99 total planned outage-days Q1'26	2022-2025 10-Ks; Q1'26 release
Owned generation capacity	MW at ownership	Pre-spin boundary	32,355	33,094	31,676	31,676	Approximately 55,000 combined post-Calpine	2022-2025 10-Ks; Calpine close release
Total owned electric supply	GWh	N/D clean annual	200,962	202,474	208,434	204,944	93,330 total supply/sales Q1'26	2023-2025 10-Ks; Q1'26 10-Q
Legacy renewable capture	Wind/solar/hydro	N/D annual	N/D annual	96.4%	96.1%	96.6%	96.7% Q1'26	2024/2025 results; Q1'26 release
Gas/oil/pumped-hydro operating metric	Dispatch match then EFOF	N/D annual	N/D annual	98.5% match	97.4% match	97.9% match	4.5% EFOF Q1'26	2024/2025 results; Q1'26 release

The FY2021 and FY2022 nuclear-output figures use the 2022 Form 10-K's revised annual series of 172.990 TWh and 173.350 TWh, respectively; the filing states that the FY2021 value was revised to reflect the correct 82% undivided ownership interest in Nine Mile Point Unit 2. FY2021 also has an ownership-comparability boundary because CEG moved from 50.01% to 100% ownership of the CENG joint venture on August 6, 2021. The annual capacity factor is nevertheless issuer-disclosed at 94.5%.

Last-four-quarter nuclear and thermal operations

Quarter	Nuclear output GWh	Capacity factor	Planned refueling days	Non-refueling days	Gas/renewables metric	Source
Q2 FY2025	45,170	94.8%	41	22	Dispatch match 98.3%; renewable capture 96.1%	2025-08-07 release

Quarter	Nuclear output GWh	Capacity factor	Planned refueling days	Non-refueling days	Gas/renewables metric	Source
Q3 FY2025	46,477	96.8%	23	5	Dispatch match 95.5%; renewable capture 96.8%	2025-11-07 release
Q4 FY2025	45,459	93.1%	63	30	Dispatch match 99.4%; renewable capture 97.2%	2026-02-24 release
Q1 FY2026	44,666	92.3%	99	0	Combined fleet EFOF 4.5%; renewable capture 96.7%	2026-05-11 release

Q1 FY2026 Calpine generation was 26,497 GWh from natural gas, oil, and renewables plus 2,089 GWh purchased power, for 28,586 GWh total segment supply/sales. The 84-day consolidated period generated $2,395 million segment revenue, $1,126 million RNF, and a 47.0% RNF margin. EFOF replaces dispatch-match rate as the combined company's principal thermal availability metric beginning in 2026.

Market reference prices—not realized prices

Region / reference ($/MWh)	FY2021	FY2022	FY2023	FY2024	FY2025
PJM West / Mid-Atlantic	38.91	72.90	33.06	33.74	50.19
ComEd / Midwest	34.76	60.24	26.64	25.50	36.62
Central / New York	29.90	57.52	26.97	34.12	56.31
North / ERCOT	146.63	64.38	55.15	26.97	32.94
Southeast Massachusetts / Other	46.38	86.02	37.35	41.70	68.56

The filings explicitly warn that these average day-ahead around-the-clock references do **not** necessarily equal prices CEG realized. Realized regional energy, capacity, and ancillary prices are not disclosed as a clean five-year table. RNF already incorporates generation, retail/load, hedge, ZEC/PTC, capacity, purchased-power, and fuel effects; downstream forecasting should therefore model RNF with disclosed drivers rather than pretending the reference series is a realized-price series.

Capacity reference prices

Capacity market / $ per MW-day	FY2021	FY2022	FY2023	FY2024	FY2025
Eastern Mid-Atlantic Area Council	174.96	126.14	69.64	51.89	179.79
ComEd / Midwest	192.45	121.71	48.64	31.09	169.50
Rest of State / New York	98.35	85.36	137.88	106.44	134.56
Southeast New England / Other	163.66	138.21	91.67	581.69	446.97

ERCOT has no centralized capacity market. CEG earns capacity and ancillary value through market-specific constructs and contract/customer portfolios. The FY2025 jump in PJM capacity references is a meaningful RNF driver, but the nuclear PTC partially offsets power/capacity upside because its credit phases down as nuclear gross receipts rise.

Hedges, contracted load, and PPAs

Item	Disclosure	Forecast use
Legacy merchant hedge plan	Three-year ratable sales plan, historically approximately 90% / 60% / 30%	Reduces prompt volatility but leaves outer-year exposure
FY2022 year-end coverage	94%-97% for 2023 and 75%-78% for 2024 across Mid-Atlantic, Midwest, New York, ERCOT	Historical benchmark only
2024-2025 sensitivity	A $5/MWh reduction was described as immaterial for the next two years, largely due to nuclear PTC	PTC is a floor, not a fixed-price contract
Calpine	Management said near-term open exposure was relatively limited because Calpine locks sales/hedges to meet commitments	Use minimum historical gross margin/volume for base case
Contracted fleet	More than 10,000 MW under long-term deals as of 2026 outlook call	Supports visible RNF and FCF

Item	Disclosure	Forecast use
Microsoft / Crane	20-year PPA for approximately 835 MW restart output, targeted second half 2027 subject to approvals	Contracted growth; restart execution risk remains
Meta / Clinton	20-year PPA beginning June 2027 for 1,121 MW; planned 30 MW uprate	Replaces expiring Illinois ZEC support
CyrusOne / Freestone	380 MW phase 1 plus exclusive 380 MW phase 2; PUCT net-metering approval subject to conditions	Calpine data-center growth; contract price undisclosed

1. Reporting structure and taxonomy

CEG's current reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, Other Power Regions, and Calpine. The five legacy segments combine owned generation and customer-facing activity by market. Calpine is the acquired natural-gas, geothermal, storage, renewable, retail, and commercial platform consolidated from January 7, 2026.

Current segment	Geography / business	FY2025 revenue	% of consolidated FY2025 revenue	TTM revenue	TTM RNF
Mid-Atlantic	Eastern PJM	6,487	25.4%	6,669	3,414
Midwest	Western PJM and non-South MISO	5,804	22.7%	6,132	3,706
New York	NYISO	2,190	8.6%	2,197	1,608
ERCOT	Texas ERCOT	1,904	7.5%	1,876	1,132
Other Power Regions	New England, South, West, Canada	5,583	21.9%	5,514	892
Calpine	Acquired operations; current issuer segment	0	0.0%	2,395	1,126
Other activities not allocated	Commercial/corporate and unallocated activity	3,565	14.0%	5,084	1,340
Consolidated	Company total	25,533	100.0%	29,867	13,218

Reporting was stable as five geographic reportable segments through FY2025. Calpine became the sixth reportable segment on acquisition. FY2025's zero Calpine row is an ER2 common-taxonomy convention, not an issuer-disclosed zero business. The 2022 Form 10-K calls RNF `Revenue Net of Purchased Power and Fuel Expense`; the sealed current label is `RNF (Operating revenues net of Purchased power and fuel expenses)`. The underlying concept remains revenue less purchased power and fuel, but downstream work must retain the sealed label.

The live FMP product endpoint should not be used as a product taxonomy. It lists the same geographic regions, has only three annual years, and misclassifies $199 million of FY2025 New York revenue. Official Note 5 figures control.

2. Consolidated historicals

Metric	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Revenue ($B)	19.649	24.440	24.918	23.568	25.533	Live FMP annual; SEC tie
Operating income ($B)	(0.346)	0.495	1.610	4.352	3.086	Live FMP annual; SEC tie
Operating margin	(1.8%)	2.0%	6.5%	18.5%	12.1%	Calculation
Net income attributable to common ($B)	(0.205)	(0.160)	1.623	3.749	2.319	Live FMP annual; SEC tie
Diluted EPS ($)	(0.63)	(0.49)	5.01	11.90	7.40	Live FMP annual; SEC tie
Diluted shares (M)	326.7	328	324	315	314	Live FMP annual; SEC tie
Capex ($B)	1.329	1.689	2.422	2.565	2.949	Live FMP cash flow
Operating cash flow ($B)	(1.338)	(2.353)	(5.301)	(2.464)	4.237	Live FMP cash flow
FCF, OCF less capex ($B)	(2.667)	(4.042)	(7.723)	(5.029)	1.288	Calculation
ROIC	(1.35%)	2.09%	6.63%	16.90%	12.00%	Normalized NOPAT / average invested capital

ROIC is calculated as statutory operating income multiplied by `(1 - 25.5%)`, divided by average beginning/end invested capital. Invested capital is total debt plus stockholders' equity less cash and cash equivalents. The 25.5% rate is the issuer's disclosed Q1 FY2026 marginal federal/state rate and avoids allowing volatile fair-value, NDT, tax-benefit, and pre-spin items to distort operating NOPAT. FY2025 example: NOPAT = $3,086 million × 74.5% = $2,299 million; average invested capital = $19,159 million; ROIC = 12.0%.

Negative FCF in 2021-2024 reflects statutory cash flow, including very large collateral and working-capital swings in 2023-2024. It is not a normalized economics estimate. FY2025 recovered to $1.288 billion, while TTM FCF through Q1 FY2026 was $1.137 billion because Q1 FY2026 capex of $1.275 billion exceeded OCF of $425 million.

3. Segment historicals

The rows below use official segment revenue and the exact RNF concept. Margins are RNF divided by revenue. Calpine had no CEG-owned historical contribution before the January 2026 close.

Mid-Atlantic	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	4.584	5.164	5.138	5.522	6.487	6.669
YoY	N/M	12.7%	(0.5%)	7.5%	17.5%	N/M
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	2.264	2.138	2.924	3.080	3.411	3.414
RNF margin	49.4%	41.4%	56.9%	55.8%	52.6%	51.2%

Midwest	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	4.060	4.650	4.658	4.805	5.804	6.132
YoY	N/M	14.5%	0.2%	3.2%	20.8%	N/M
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	2.717	2.764	3.255	3.202	3.702	3.706
RNF margin	66.9%	59.4%	69.9%	66.6%	63.8%	60.4%

New York	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	1.575	1.595	2.021	2.050	2.190	2.197
YoY	N/M	1.3%	26.7%	1.4%	6.8%	N/M
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	1.161	1.067	1.251	1.453	1.600	1.608
RNF margin	73.7%	66.9%	61.9%	70.9%	73.1%	73.2%

ERCOT	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	1.181	1.543	1.346	1.550	1.904	1.876
YoY	N/M	30.7%	(12.8%)	15.2%	22.8%	N/M
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	(0.825)	0.407	0.582	1.047	1.137	1.132
RNF margin	(69.9%)	26.4%	43.2%	67.5%	59.7%	60.3%

Other Power Regions	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	4.890	6.732	5.851	5.506	5.583	5.514
YoY	N/M	37.7%	(13.1%)	(5.9%)	1.4%	N/M
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	0.891	0.921	1.240	1.268	0.819	0.892
RNF margin	18.2%	13.7%	21.2%	23.0%	14.7%	16.2%

Calpine	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
Revenue ($B)	Not CEG-owned	Not CEG-owned	Not CEG-owned	Not CEG-owned	0.000	2.395

Calpine	FY2021	FY2022	FY2023	FY2024	FY2025	TTM
RNF (Operating revenues net of Purchased power and fuel expenses) ($B)	Not CEG-owned	Not CEG-owned	Not CEG-owned	Not CEG-owned	0.000	1.126
RNF margin	N/M	N/M	N/M	N/M	N/M	47.0%

The Calpine TTM number is only its Q1 FY2026 contribution because CEG did not own it in the other three TTM quarters. It is not a full-year run rate. Q1 consolidated Calpine revenue from the acquisition date was $3,136 million; Note 5 assigns $2,395 million to the Calpine segment and the balance under the issuer's disclosed unallocated taxonomy. Do not scale $1,126 million RNF mechanically by four without accounting for the six missing January days, seasonality, hedge roll, capacity periods, divestitures, and purchase-accounting effects.

3a. Historical statutory-profit bridge and forecast-driver ledger

QFR-sealed SHA-256: `227bdac4e38cca9b15f36fef332cef5fb35d00faab35013a0f6d4841dc02a0be` **Common segment profit basis:** `RNF (Operating revenues net of Purchased power and fuel expenses)` **Segment profit basis:** issuer disclosed; not statutory operating income.

FY2025 bridge

Bridge line	Classification	Value	Source ID	Running subtotal
Mid-Atlantic	segment profit	3,411	SEC_FY2025_10K	3,411
Midwest	segment profit	3,702	SEC_FY2025_10K	7,113
New York	segment profit	1,600	SEC_FY2025_10K	8,713
ERCOT	segment profit	1,137	SEC_FY2025_10K	9,850
Other Power Regions	segment profit	819	SEC_FY2025_10K	10,669
Calpine	segment profit	0	SEC_FY2025_10K	10,669
Sum of reportable segment profit	segment profit	10,669	SEC_FY2025_10K	10,669
Other activities not allocated to a segment	corporate unallocated	183	SEC_FY2025_10K	10,852
Consolidated segment profit metric	subtotal	10,852	SEC_FY2025_10K	10,852
Operating and maintenance	operating	(6,159)	SEC_FY2025_10K	4,693
Depreciation and amortization	operating	(985)	SEC_FY2025_10K	3,708
Taxes other than income taxes	operating	(622)	SEC_FY2025_10K	3,086
Statutory operating income	statutory subtotal	3,086	SEC_FY2025_10K	3,086
Interest expense, net	interest	(511)	SEC_FY2025_10K	2,575
Other, net	other non-operating	936	SEC_FY2025_10K	3,511
Pretax income	statutory subtotal	3,511	SEC_FY2025_10K	3,511
Income tax expense plus equity in losses of unconsolidated affiliates	tax	(1,188)	SEC_FY2025_10K	2,323
Net income attributable to noncontrolling interests	noncontrolling interests	(4)	SEC_FY2025_10K	2,319
Net income	statutory subtotal	2,319	SEC_FY2025_10K	2,319

TTM ended 2026-03-31 bridge

Bridge line	Classification	Value	Source ID	Running subtotal
Mid-Atlantic	segment profit	3,414	TTM_NORMALIZED_RECONCILIATION	3,414
Midwest	segment profit	3,706	TTM_NORMALIZED_RECONCILIATION	7,120
New York	segment profit	1,608	TTM_NORMALIZED_RECONCILIATION	8,728

Bridge line	Classification	Value	Source ID	Running subtotal
ERCOT	segment profit	1,132	TTM_NORMALIZED_RECONCILIATION	9,860
Other Power Regions	segment profit	892	TTM_NORMALIZED_RECONCILIATION	10,752
Calpine	segment profit	1,126	TTM_NORMALIZED_RECONCILIATION	11,878
Sum of reportable segment profit	segment profit	11,878	TTM_NORMALIZED_RECONCILIATION	11,878
Other activities not allocated to a segment	corporate unallocated	1,340	TTM_NORMALIZED_RECONCILIATION	13,218
Consolidated segment profit metric	subtotal	13,218	TTM_NORMALIZED_RECONCILIATION	13,218
Operating and maintenance	operating	(6,394)	TTM_NORMALIZED_RECONCILIATION	6,824
Depreciation and amortization	operating	(1,180)	TTM_NORMALIZED_RECONCILIATION	5,644
Taxes other than income taxes	operating	(691)	TTM_NORMALIZED_RECONCILIATION	4,953
Gain on sales of assets	operating	14	TTM_NORMALIZED_RECONCILIATION	4,967
Statutory operating income	statutory subtotal	4,967	TTM_NORMALIZED_RECONCILIATION	4,967
Interest expense, net	interest	(618)	TTM_NORMALIZED_RECONCILIATION	4,349
Other, net	other non-operating	1,136	TTM_NORMALIZED_RECONCILIATION	5,485
Pretax income	statutory subtotal	5,485	TTM_NORMALIZED_RECONCILIATION	5,485
Income tax expense plus equity in income of unconsolidated affiliates	tax	(1,688)	TTM_NORMALIZED_RECONCILIATION	3,797
Net income attributable to noncontrolling interests	noncontrolling interests	(6)	TTM_NORMALIZED_RECONCILIATION	3,791
Net income	statutory subtotal	3,791	TTM_NORMALIZED_RECONCILIATION	3,791

Both anchors have zero residuals across segment sum, corporate bridge, operating-income bridge, pretax bridge, and net-income bridge. The Other Power Regions quarterly display sums to $893 million, but the sealed same-window computation is FY2025 $819 million less Q1 FY2025 $194 million plus Q1 FY2026 $267 million = $892 million, within the $1 million reporting scale.

Forecast-driver ledger

Historical bridge line	FY value	TTM value	Forecast treatment	Driver and source	Bear / base / bull rule
Other activities not allocated to a segment	183	1,340	Independently forecast unallocated RNF	Commercial/retail margin, consolidated Calpine activity, fair-value effects; Note 5	Bear normalizes sharply; base uses disclosed commercial framework; bull requires evidenced contract margin
Operating and maintenance	(6,159)	(6,394)	Independent operating expense	Fleet capacity, outage schedule, inflation, Calpine integration; 10-K and outlook deck	Bear high inflation/outages; base management plan; bull synergies only when captured
Depreciation and amortization	(985)	(1,180)	PP&E and purchase-accounting schedule	Capex, Calpine fair-value step-up, asset lives	Bear higher capex/D&A; base purchase accounting; bull no unsupported D&A reduction
Taxes other than income taxes	(622)	(691)	Percentage of revenue plus jurisdiction schedule	Historical ratio and combined fleet footprint	Bear upper historical ratio; base normalized ratio; bull lower bound only if sourced

Historical bridge line	FY value	TTM value	Forecast treatment	Driver and source	Bear / base / bull rule
Gain on sales of assets	0	14	Zero recurring base	Discrete asset sales	Bear/base zero; bull recognizes only announced and probability-weighted disposals
Interest expense, net	(511)	(618)	Debt and rate schedule	$22,466m Q1 debt, repayments, maturities, issued coupons	Bear slow deleveraging/high rates; base $3.4bn deleveraging by end-2027; bull faster only from realized proceeds
Other, net	936	1,136	Component-based non-operating schedule	NDT/decommissioning and other disclosed items	Do not extrapolate TTM wholesale; use conservative normalized range
Income tax plus affiliate income/loss	(1,188)	(1,688)	Tax-rate schedule plus affiliate items	25.5% marginal rate and statutory disclosures	Bear higher effective; base 25.5% normalized; bull requires tax-credit evidence
Noncontrolling interests	(4)	(6)	Separate minority-interest schedule	Asset ownership structure	Maintain explicit negative line; no generic tax plug

`STATUTORY_BRIDGE_STATUS: VERIFIED — CLEARED FOR FORECASTING`

4. Product and sub-segment historicals

CEG does not disclose a conventional product hierarchy below reportable geography in dollars. Its finest consistently disclosed economic table is regional revenue, purchased power/fuel, and RNF. Consolidated revenue from power sales and natural-gas sales is disclosed, but that split is not a second additive reportable-segment taxonomy.

Segment	Product / economic unit	What it is	Dollar disclosure?	Last three annual revenue observations
Mid-Atlantic	Regional generation and customer portfolio	Eastern PJM	Yes	FY2023 $5.138B; FY2024 $5.522B; FY2025 $6.487B
Midwest	Regional generation and customer portfolio	Western PJM and MISO	Yes	FY2023 $4.658B; FY2024 $4.805B; FY2025 $5.804B
New York	Regional generation and customer portfolio	NYISO	Yes	FY2023 $2.021B; FY2024 $2.050B; FY2025 $2.190B
ERCOT	Regional generation and customer portfolio	Texas energy-only market	Yes	FY2023 $1.346B; FY2024 $1.550B; FY2025 $1.904B
Other Power Regions	Regional generation and customer portfolio	New England, South, West, Canada	Yes	FY2023 $5.851B; FY2024 $5.506B; FY2025 $5.583B
Calpine	Acquired thermal/geothermal/retail platform	Gas, geothermal, storage, solar, retail	Q1'26 only under CEG	Q1 FY2026 $2.395B segment revenue

Segment / product	Disclosure method	Last-four-quarter trend disclosed	Source
Nuclear fleet	Output, capacity factor, outage days; no standalone revenue	Output 45.170 / 46.477 / 45.459 / 44.666 TWh	Quarterly releases
Legacy gas/oil/renewables	Dispatch match then renewable capture	Dispatch 98.3% / 95.5% / 99.4%; Q1 combined EFOF 4.5%	Quarterly releases
Retail/customer solutions	Customer volumes disclosed post-Calpine	Approximately 275m MWh electricity and 800 Bcf gas annually	Q1 FY2026 call
Data-center contracts	MW and duration, not contract revenue or price	Microsoft 835 MW; Meta 1,121 MW; CyrusOne 380 MW plus 380 MW exclusive phase	Official releases

No product dollars are back-solved. Contract prices and realized regional selling prices remain true non-disclosures.

5. Most recent quarterly trend

Company FY ends December 31. Most recently completed fiscal quarter at the cutoff: FY2026 Q1, covering January-March 2026, reported on 2026-05-11 via the [official release](https://investors.constellationenergy.com/news-releases/news-release-details/constellation-reports-first-quarter-2026-results).

The table uses exact RNF margin, not segment operating margin; CEG does not disclose statutory operating income by reportable segment.

Segment / quarter	Revenue ($B)	YoY	RNF ($B)	RNF margin	Source
Mid-Atlantic Q2'25	1.448	11.0%	0.782	54.0%	Q2'25 10-Q Note 5
Mid-Atlantic Q3'25	1.763	10.0%	0.892	50.6%	Q3'25 10-Q Note 5
Mid-Atlantic Q4'25	1.611	17.2%	0.928	57.6%	FY less 9M
Mid-Atlantic Q1'26	1.847	10.9%	0.812	44.0%	Q1'26 10-Q Note 5
Midwest Q2'25	1.524	30.5%	1.036	68.0%	Q2'25 10-Q Note 5
Midwest Q3'25	1.390	9.0%	0.943	67.8%	Q3'25 10-Q Note 5
Midwest Q4'25	1.487	17.3%	0.874	58.8%	FY less 9M
Midwest Q1'26	1.732	23.4%	0.854	49.3%	Q1'26 10-Q Note 5
New York Q2'25	0.535	4.1%	0.397	74.2%	Q2'25 10-Q Note 5
New York Q3'25	0.558	10.1%	0.399	71.5%	Q3'25 10-Q Note 5
New York Q4'25	0.535	3.7%	0.403	75.3%	FY less 9M
New York Q1'26	0.569	1.2%	0.409	71.9%	Q1'26 10-Q Note 5
ERCOT Q2'25	0.464	30.0%	0.271	58.4%	Q2'25 10-Q Note 5
ERCOT Q3'25	0.628	20.1%	0.415	66.1%	Q3'25 10-Q Note 5
ERCOT Q4'25	0.415	18.9%	0.237	57.1%	FY less 9M
ERCOT Q1'26	0.370	(7.0%)	0.209	56.5%	Q1'26 10-Q Note 5
Other Power Regions Q2'25	1.178	(0.5%)	0.181	15.4%	Q2'25 10-Q Note 5
Other Power Regions Q3'25	1.543	6.9%	0.343	22.2%	Q3'25 10-Q Note 5
Other Power Regions Q4'25	1.306	4.1%	0.102	7.8%	FY less 9M
Other Power Regions Q1'26	1.487	(4.4%)	0.267	18.0%	Q1'26 10-Q Note 5
Calpine Q1'26	2.395	N/M	1.126	47.0%	Q1'26 10-Q Note 5

The largest current segment by revenue is Mid-Atlantic. Its Q1 FY2026 revenue growth spot-check is $1.847 billion versus $1.665 billion, or 10.9%, confirmed in the live Q1 10-Q. The largest RNF segment is Midwest on a TTM basis at $3.706 billion.

6. Management commentary on forward growth

All quotations below come from live FMP transcript pulls whose dates matched the fiscal calls: 2025-08-07, 2025-11-07, 2026-03-31, and 2026-05-11. Quotes are kept short and verbatim.

Fiscal call / speaker	Topic	Verbatim statement	Modeling implication
Q2 FY2025, 2025-08-07; Joe Dominguez, CEO	Calpine value	“Calpine will add $2 in EPS and $2 billion of free cash flow before growth starting next year.”	Initial deal case; test against current combined guidance
Q2 FY2025, 2025-08-07; Joe Dominguez	Contract strategy	“long-term contracts like our Meta and Microsoft deals” are becoming “an ordinary part of our strategy”	Contracting is recurring strategy, not one-off
Q3 FY2025, 2025-11-07; Dan Eggers, CFO	Calpine hedges	“near-term open exposure is relatively limited”	Do not mark the full gas fleet to current spot immediately
Q4 FY2025, 2026-03-31; Joe Dominguez	Contracted fleet	“executed deals for over 10,000 megawatts of our fleet”	Base case should distinguish contracted from merchant output
Q4 FY2025, 2026-03-31; Shane Smith, CFO	FCF accretion	“at least $2 billion of annual incremental free cash flow”	Core acquisition cash-conversion test
Q4 FY2025, 2026-03-31; Shane Smith	Growth capex	“$3.9 billion in growth projects” with “returns of at least 10% on an unlevered basis”	Separate growth capex from maintenance and require return evidence
Q4 FY2025, 2026-03-31; Shane Smith	Deleveraging	“earmarked $3.4 billion to delever the Calpine debt stack”	Base debt schedule target through end-2027
Q4 FY2025, 2026-03-31; Shane Smith	Thermal base	“minimum expected gross margin and volume grounded in historical experience”	Calpine base should not assume full spot upside
Q1 FY2026, 2026-05-11; Joe Dominguez	FCF outlook	“the '26, '27 period producing a forecasted $8.4 billion”	Two-year combined FCF-before-growth anchor
Q1 FY2026, 2026-05-11; Joe Dominguez	Longer FCF	“the '28-'29 period rising to $11.5 billion to $13 billion”	Treat as management range before optionality levers

Fiscal call / speaker	Topic	Verbatim statement	Modeling implication
Q1 FY2026, 2026-05-11; Andrew Novotny, Calpine CEO	ERCOT hedge	“we've been well hedged and protected against it”	Near-term weak forwards need not equal immediate RNF collapse
Q1 FY2026, 2026-05-11; Shane Smith	Customer scale	“approximately 275 million megawatt hours of electricity and 800 Bcf of natural gas annually”	Commercial scale and cross-sell denominator

Management affirmed FY2026 adjusted operating EPS guidance of $11.00-$12.00 on May 11. That adjusted figure is not a statutory bridge line. The model must bridge RNF to GAAP operating income, pretax income, and common net income before using it as a reasonableness check.

7. Capital allocation history

Year	Capex ($B)	Capex / revenue	R&D ($B)	Buybacks ($B)	Dividends ($B)	M&A net cash-flow line ($B)	Source
FY2021	1.329	6.8%	N/D	0.064	1.832	1.329	Live FMP; pre-spin basis
FY2022	1.689	6.9%	N/D	1.750	0.185	0.052	Live FMP; separation effects
FY2023	2.422	9.7%	N/D	0.992	0.366	0.024	Live FMP
FY2024	2.565	10.9%	N/D	0.999	0.444	(0.032)	Live FMP
FY2025	2.949	11.5%	N/D	0.400	0.486	(0.014)	Live FMP

R&D is a true non-disclosure in FMP financial statements and the checked 10-K operating-expense tables; it is embedded in other expense categories rather than separately stated. FY2021 dividends and FY2022 repurchase-like cash flows are not directly comparable with post-spin public-company capital return. M&A cash-flow signs reproduce the FMP statement line and should not replace acquisition purchase-price accounting.

The 2026 outlook identified $13.6 billion deployable over 2026-2027 after expected asset-sale proceeds, $3.9 billion growth investment, $3.4 billion deleveraging, 10% annual dividend growth, and a $5 billion repurchase authorization. On June 1, 2026, selling Calpine holders offered 11 million shares at $281, and CEG agreed to repurchase 2 million of those shares. That is a post-Q1 action; it does not mutate the sealed Q1 diluted-share anchor.

8. Balance-sheet snapshot and Calpine-inclusive decision inputs

Item at 2026-03-31	$B	Source / interpretation
Cash and equivalents	0.800	Official Q1 10-Q cash-only
Restricted cash	0.371	Shown separately; FMP combines it with cash
Short-term investments	0.000	Live FMP / official balance sheet
Short-term borrowings	5.102	Official Q1 10-Q
Current long-term debt	0.370	Official Q1 10-Q
Long-term debt	16.994	Official Q1 10-Q
Total debt	22.466	Sum of three debt lines
Net debt, cash-only	21.666	$22.466B less $0.800B
Net debt / annualized Q1 adjusted EBITDA	Not decision-safe	Quarterly acquisition timing and fair-value items distort denominator
Goodwill	11.527	Q1 purchase accounting; preliminary allocation
Stockholders' equity	33.483	Live FMP tied to official filing
Equity less goodwill only	21.956	$33.483B equity less $11.527B goodwill; not full tangible book value because additional acquired intangibles are embedded in other asset lines
Q1 diluted weighted-average shares	354M	Current earnings denominator sealed in quote packet
Period-end common shares	362M	Official cover/balance basis
Available credit-facility capacity	6.682	Official Q1 liquidity disclosure

At the Calpine close, CEG issued approximately 50 million shares and paid $4.342 billion cash; the fair value of issued shares was $17.603 billion and total merger consideration was $21.835 billion. CEG assumed approximately $12.6 billion of Calpine debt, including $7.6 billion corporate debt and $5.0 billion project financing. It repaid $2.5 billion corporate term loans at close, $1.25 billion secured notes in February, and $1.4 billion unsecured notes in March. Q1 gross debt of $22.466 billion is the post-repayment, Calpine-inclusive balance.

Management earmarked $3.4 billion for further deleveraging by end-2027 and expects target Baa1/BBB+ metrics. The bear case should delay asset-sale proceeds and retain higher interest expense; the base may use announced proceeds only with timing and closing discounts; the bull must not double-count asset-sale cash as both debt reduction and distributable cash.

Cash conversion must be evaluated from current pro forma economics rather than the legacy FY2025 $1.288 billion FCF. Management's $8.4 billion 2026-2027 FCF-before-growth and $11.5-$13.0 billion 2028-2029 range exclude growth deployment and need reconciliation for maintenance capex, cash tax, integration, working capital, and divestitures. Q1 statutory OCF of $425 million and capex of $1.275 billion produced negative $850 million quarterly FCF, showing that seasonal/transactional conversion is not linear.

9. Recent corporate actions and regulatory exposures

- **2025-06-03:** CEG signed a 20-year Meta PPA beginning June 2027 for the Clinton plant's 1,121 MW output and a planned 30 MW uprate. Contract price is confidential.
- **2025-12-05:** DOJ/FERC resolution required divestiture of PJM and ERCOT assets as a condition to Calpine clearance.
- **2026-01-07:** Calpine acquisition closed for $21.835 billion purchase consideration, including approximately 50 million issued CEG shares and $4.342 billion cash.
- **2026-02-09:** Calpine signed a 380 MW CyrusOne Freestone agreement plus an exclusive additional 380 MW phase; Q1 later disclosed conditional PUCT net-metering approval.
- **2026-03-18:** CEG agreed to sell approximately 4.4 GW of PJM gas capacity to LS Power for $5 billion before closing adjustments, subject to approvals. The remaining DOJ package included Jack Fusco and Gregory interests.
- **2026-03-31:** Combined-company guidance set adjusted EPS at $11-$12, $8.4 billion 2026-2027 FCF before growth, $3.4 billion deleveraging, and $5 billion buyback authorization.
- **2026-04-30:** 460 MW Pin Oak Creek peaker achieved commercial operation in ERCOT; this is operational evidence reported May 11 and permitted by the cutoff.
- **2026-05-11:** Q1 results affirmed guidance. Calpine delivered $1.126 billion RNF in the acquisition-date-to-quarter-end period.
- **2026-06-01:** Calpine holders sold 11 million CEG shares in a secondary offering at $281; CEG repurchased 2 million. Half of the original 50 million consideration shares had a June 30, 2026 lockup expiry and the other half June 30, 2027.
- **Leadership:** Dan Eggers became Senior EVP, Finance and Data Economy; Shane Smith became EVP and CFO; Andrew Novotny continues to lead Calpine. This concentrates finance, data-economy contracting, and integration accountability in named executives.

Primary exposures are PJM/FERC/DOJ market-power remedies, NRC license/restart approvals, state ZEC/CMC structures, the federal nuclear PTC and its gross-receipts phase-down, ERCOT co-location/net-metering conditions, gas and power commodity prices, congestion/basis, outage performance, fuel/nuclear supply, environmental regulation, asset-sale execution, and investment-grade collateral requirements. The Q1 filing estimated that a below-investment-grade downgrade could require approximately $3.0 billion additional collateral versus $6.682 billion available facilities plus $0.800 billion cash.

10. Open data gaps and modeling guardrails

Gap	Classification	Sources and searches completed	Required treatment
Realized energy/capacity/ancillary price by region	True non-disclosure	2022-2025 10-K MD&A; `realized price`, `capacity`, `ancillary`, `RNF`	Use RNF and reference-price/hedge drivers; do not relabel references as realized
Contract prices for Microsoft, Meta, CyrusOne	True non-disclosure	Official PPA releases, 10-K/10-Q, transcripts	Use duration/MW; scenario price ranges must be externally justified

Gap	Classification	Sources and searches completed	Required treatment
Full annual Calpine history on CEG RNF taxonomy	Not applicable before ownership; current partial disclosure	Q1 10-Q Note 5, pro forma 8-K/A, Calpine acquisition material	Q1 is partial-period; avoid 4× annualization
Calpine operating-region RNF split	True non-disclosure under CEG taxonomy	Q1 10-Q Note 5; searched West, Texas, East, Retail	Model Calpine as one reportable segment unless issuer restates
Segment statutory operating income	True non-disclosure	Segment notes in 2022-2025 10-Ks and Q1 10-Q	Forecast RNF, then preserve statutory bridge
R&D expense	True non-disclosure	FMP income/cash flow and 10-K operating-expense tables	Do not insert zero; include within disclosed operating expense categories
Maintenance versus growth capex history	True non-disclosure as a clean five-year split	10-K capex, outlook decks, transcripts	Use total statutory capex history; forward split must cite project schedules
FY2021 owned-capacity comparable	Estimated / taxonomy boundary	2022 10-K and pre-spin ownership descriptions	Do not backfill a false comparable MW total
Q2 FY2026 results	Not applicable at cutoff	Official event schedule and SEC inventory	Excluded; mandatory refresh trigger
Direct archive of Q1 IR HTML	Not fetched / omitted	Identical direct HTTP download timed out twice; live IR page and SEC 10-Q were fetched	Use live IR URL and archived SEC filing; no cache fallback

Critical guardrails for downstream work:

- RNF is the exact forecast segment metric and must never be renamed operating income.
- Calpine enters only from January 7, 2026; FY2025 revenue and RNF are zero on the CEG ownership basis.
- Use $22.466 billion gross debt, $21.666 billion cash-only net debt, 354 million Q1 diluted shares, and 362 million period-end shares as distinct decision inputs.
- Do not use FMP's $2.389 billion FY2025 New York product row; official revenue is $2.190 billion.
- Do not sum quarterly EPS. TTM common net income of $3.791 billion divided by day-weighted 323.358904 million shares is $11.723815.
- Treat the $5 billion LS Power sale as conditional until closing and avoid double-counting proceeds.
- Treat nuclear PTC as a floor with a gross-receipts phase-down, not additive upside at every power price.
- Q2 FY2026 is excluded even if later web pages exist; the evidence boundary is fixed at 2026-08-06 09:02:30 SGT.

Source-control record

The most load-bearing figures were rechecked live in this run:

- Q1 FY2026 Mid-Atlantic revenue was $1.847 billion versus $1.665 billion, confirming 10.9% growth in the official 10-Q.
- The Q1 FY2026 FMP transcript dated 2026-05-11 contained the $8.4 billion 2026-2027 and $11.5-$13.0 billion 2028-2029 FCF-before-growth statements.
- Live FMP annual income statement reported FY2025 revenue of $25.533 billion, exactly tying the 2025 Form 10-K.
- `statutory_bridge.json` recomputed SHA-256 equals `227bdac4e38cca9b15f36fef332cef5fb35d00faab35013a0f6d4841dc02a0be`.

All historical dollar values above are sourced from live FMP stable pulls or official SEC/IR evidence fetched during this run. No cached transcript, financial, segment, or price file was substituted.