OMNGC Briefing Packet — The Good, the Bad & the Ugly

Prepared for Bill Tackett · July 1, 2026 · Dekacern

We replayed the past six months — November through April — town by town, as a sealed-clock test: on each bid-week the model decided using only what was knowable that day, then we scored it against what the schedulers actually did. This packet walks through three towns that show what the model does well, where it falls short, and where it misses badly — because the schedulers' judgment is exactly what closes those gaps — then the combined outcome across every town, and the two fixes we have already built from what the schedulers taught us.

The bottom line, across all towns, over the past six months

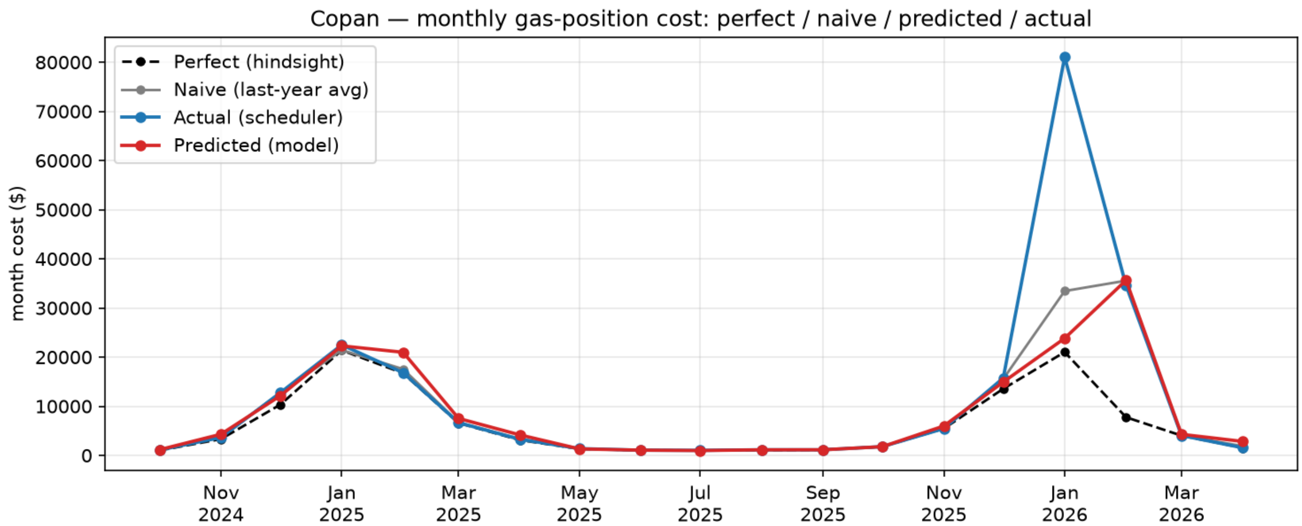
The model came in WORSE than the schedulers by $281,812 — 6.5% (model $4,616,738 vs the schedulers' $4,334,926 across 17 towns). That headline is honest, but it is not the story: the result splits cleanly by pipeline. The model **beats** the schedulers on Southern Star and Enable, and **loses on every OGT town** — because OGT is where it has no storage and no confirmed pooling to work with, so it self-insures against cold with expensive baseload. The three acts that follow are one example of each; the combined table at the end shows all of it, and points straight at the fix.

Same sealed-clock rules as always: the model never sees the future, each winter it weighs is a past winter, and the AI writes only the explanation — never the number. "Perfect" is hindsight, shown as the yardstick for how much was even possible.

THE GOOD

Copan — a grand-slam winter on Southern Star

Over the past six months the model beat the schedulers by **+$49,177** (model $167,463 vs $216,640) — about 23% cheaper.



Almost the whole win is one month — **January 2026**, the hard cold snap:

Month	Monthly price	Use avg / peak	Scheduler / day	Model / day	Scheduler cost	Model cost	Model vs sched.
2026-01	$4.34	156 / 271	20	227	$81,059	$23,827	+$57,232

The model saved $57,232 in that single month. The schedulers carried almost no baseload into January (20/day) and had to buy the cold days on the daily market right as prices spiked; the model had already committed 227/day at the monthly price — close to the perfect 270 — and rode the snap out cheaply.

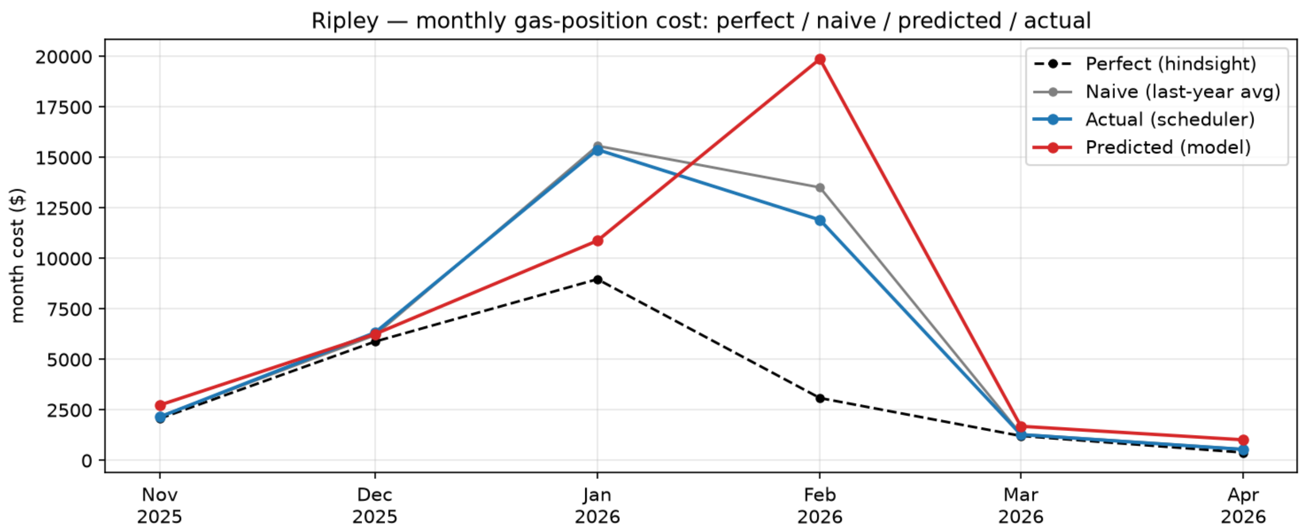
This is the model's core value: **it is not caught short on the cold month.** And on Southern Star it can afford to lean long, because the tolerance band and member-to-member pooling let it place any unused gas cheaply when a month turns mild — so the insurance is nearly free here.

Where the schedulers help: Copan is where the model is strongest — so this is where we most want to **confirm the mechanics we are relying on**: the Southern Star pooling and tolerance terms, and the sell-back price for unused gas. Nail those down and this becomes a decision the system can be trusted to make on its own.

THE BAD

Ripley — wins the cold, gives it back on a panic month

Over six months the model came in **−$4,854** (model $42,466 vs $37,612) — a small net loss on an OGT town.



Two months tell the whole story:

Month	Monthly price	Use avg / peak	Scheduler / day	Model / day	Scheduler cost	Model cost	Model vs sched.
2026-01	$4.29	68 / 137	80	111	$15,390	$10,881	+$4,509
2026-02	$7.86	34 / 73	60	107	$11,911	$19,876	−$7,965

In **January 2026** the model does exactly what it did for Copan — carries the baseload the schedulers didn't, and **wins +$4,509** on the cold snap. Then **February 2026** undoes it: the monthly price printed a panic **$7.86**, the model committed 107/day — and the month came in **warm** (used 34/day), so all that expensive baseload sold back at the low daily price for a **−$7,965** loss.

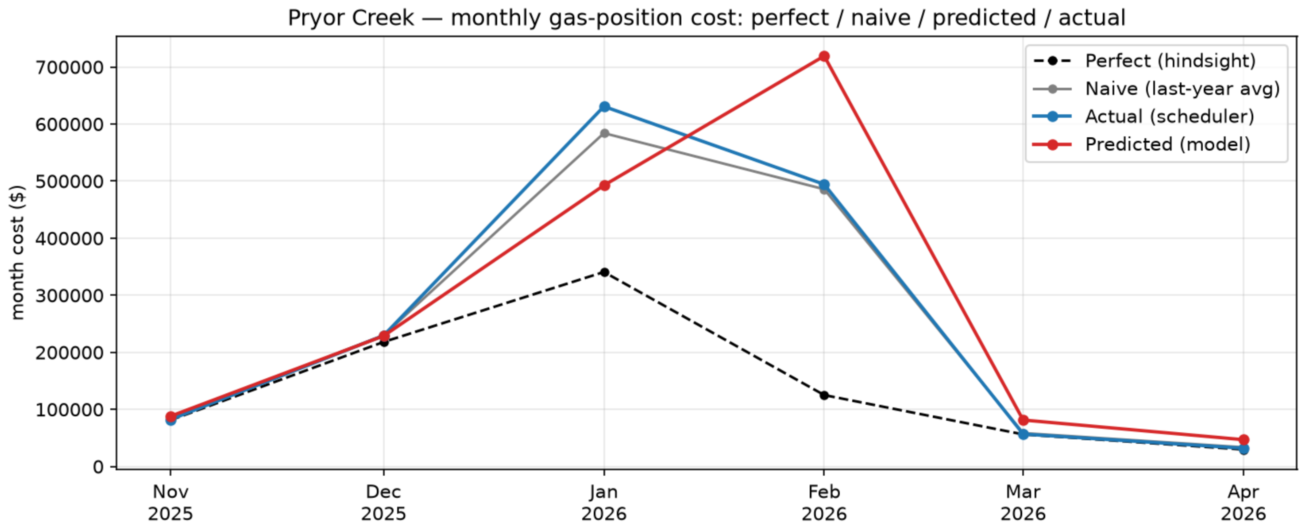
Why here and not Copan? Because Ripley is on **OGT**, where the model has **no storage** to lean on. It can't size baseload lean and cover a cold day from an account — so it self-insures with baseload, and when a panic price meets a warm month, that baseload is a loss. (Our panic-price safeguard pulled the buy down, but couldn't erase it — Ripley's only past Februaries were cold, so its "normal" is high.)

> **Where the schedulers help:** in February 2026 the schedulers bought lean into that panic price — and were **right**. What is the rule of thumb for a panic bid-week? That judgment is exactly what the model is missing, and it is the same thing on-system storage would give it. Tell us how you read a first-of-month that prints double its normal, and we can encode it.

THE UGLY

Pryor Creek — the same mistake, forty times the size

Over six months the model missed by **−$131,313** (model $1,656,806 vs $1,525,493) — the single biggest gap in the fleet, and the clearest case for storage on OGT.



Pryor Creek is the coalition's largest OGT town, and it repeats Ripley's pattern at scale:

Month	Monthly price	Use avg / peak	Scheduler / day	Model / day	Scheduler cost	Model cost	Model vs sched.
2026-01	$4.29	2562 / 4773	2540	3358	$630,818	$492,559	+$138,259
2026-02	$7.86	1380 / 2938	2500	3816	$494,296	$719,163	−$224,867

In **January 2026** the model is a hero — the schedulers were caught short on the cold snap and the model **saved +$138,259**. Then **February 2026**: the same panic **$7.86** monthly price, and the model bought **3816/day** for a month that used 1380 and needed essentially **no extra baseload at all** (perfect was 0). The result was a **−$224,867** miss in one month.

This is what storage would fix. With an on-system storage account, the engine would size February 2026's baseload lean and draw from storage on the cold days — instead of committing 3816/day at a panic price it can't take back. On the towns that already have storage (Mannford, Drumright), sizing them collectively with their storage turns a loss into a roughly **$1.9 million** win over six years. Pryor Creek is the biggest town that has none.

> **Where the schedulers help:** in February 2026 the schedulers held near 2500/day and were right that the panic price would revert. How did you know? And is on-system ONEOK storage worth pursuing for the big OGT towns? This is the top item we want to work through together.

The combined outcome — all towns, the past six months

Sealed-clock replay, November 2025 – April 2026, each town scored against its own recorded decisions on real published prices.

Town	Pipeline	Months	Scheduler cost	Model cost	Model vs scheduler
Drumright †	Southern Star	6	$368,144	$312,309	+$55,835
Copan	Southern Star	19	$216,640	$167,463	+$49,177
Granite	Enable/ EGT	6	$114,923	$106,324	+$8,599
Minco	OGT	4	$184,527	$177,964	+$6,563
Burlington	Southern Star	6	$42,603	$37,121	+$5,482
Wakita	Southern Star	6	$42,136	$37,315	+$4,821
Orlando	Southern Star	4	$20,424	$17,701	+$2,723
Roland	Enable/ EGT	5	$93,292	$93,615	−$323
Ripley	OGT	6	$37,612	$42,466	−$4,854
Cashion	OGT	6	$83,512	$89,726	−$6,214
Geary	OGT	6	$137,817	$145,097	−$7,280
Yale	OGT	6	$64,165	$75,718	−$11,553
Jones	OGT	6	$228,518	$250,136	−$21,618
Sperry	OGT	6	$154,158	$176,569	−$22,411
Tuttle	OGT	6	$685,384	$739,561	−$54,177
Pryor Creek	OGT	6	$1,525,493	$1,656,806	−$131,313
Mannford †	Southern Star	6	$335,578	$490,847	−$155,269
ALL TOWNS — before fixes		**–**	**$4,334,926**	**$4,616,738**	**−$281,812**
ALL TOWNS — today, deployed (OGT anchor on)		**–**	**$4,334,926**	**$4,530,284**	**−$195,358**

Before the fixes this winter the model was **6.5% worse** overall; with the OGT anchor now live it is **4.5% behind** and closing — but read the pipeline column and the story is not "the model is behind," it is **"the model is behind on OGT,"** and the two pages that follow are the fixes that close it. It **wins** on Southern Star and Enable, where it has the tolerance band, pooling, and (for two towns) storage to work with. It **loses on every OGT town**, where it has none of those and simply over-buys baseload.

† **Mannford is the exception that proves the rule.** Mannford and Drumright are Southern Star storage towns — but scored here with their storage **not engaged**, Mannford is the single worst line in the table. Turn its storage on — the way the system now sizes it — and it becomes a top winner. That one row is the entire argument: **the model is only as good as the flexibility we give it.**

So this is a map, not a verdict — and two of the three fixes are **already built** (the next two pages): **(1) the OGT anchor**, which teaches the model the schedulers' lean-buying rule, and **(3) demand tracking** for fast-growing towns. Still ahead: **(2) storage on OGT** — the ONEOK Gas Storage question, worth the most on the big towns like Pryor Creek — and pooling across OGT towns so one town's surplus covers another's shortfall at no cost. Give the model the tools it already has on Southern Star, and the OGT column follows.

Every month scored on real published daily and first-of-month prices, each stamped with the instant it was published. The model carries cold-snap insurance in every winter month and the schedulers' totals do not — how much of that insurance to carry is a coalition decision, not a software one.

The first fix, and its full results — OGT

Learning the schedulers' OGT rule and putting it in the model. Same sealed-clock replay, November 2025 – April 2026, every OGT town.

The combined table said the gap is **on OGT** — where the model has no storage and simply over-buys baseload. So we studied how your schedulers actually buy on OGT, and the rule was clear: **they buy close to what the town will burn** (about 1.0× expected usage), cover the cold-day spikes on the spot market, and do **not** carry a big standing cushion — because with no storage, gas bought and not burned is stranded and sold back at a loss. The model had been buying ~1.6×. We taught the engine that rule and measured it against your schedulers, town by town, on real prices:

OGT town	Model vs scheduler — before	Model vs scheduler — after the fix	Recovered
Pryor Creek	−$131,313	−$81,951	+$49,362
Tuttle	−$54,177	−$39,035	+$15,142
Sperry	−$22,410	−$14,709	+$7,701
Jones	−$21,618	−$13,177	+$8,441
Yale	−$11,552	−$7,898	+$3,654
Geary	−$7,280	−$2,299	+$4,981
Cashion	−$6,214	−$4,435	+$1,779
Ripley	−$4,854	−$3,218	+$1,636
Minco	+$6,563	+$321	−$6,242
ALL OGT TOWNS	**−$252,855**	**−$166,401**	**+$86,454**

The fix recovered $86,454 — about a third of the entire OGT gap — in one change, and every town improved but Minco (already a winner, and our thinnest history). It is now live in the model.

Did it break anything? The full check

We put the change through the same gauntlet we hold every change to — it has to help OGT **without** hurting the towns we already win, and without giving up the cold-snap protection that is the model's whole point:

Check	Result
Southern Star towns (Copan, Drumright…)	**Unchanged — byte-for-byte. The fix only touches OGT.**

Whole fleet vs. the naïve "just buy last year" benchmark	**−2.5% → −0.2% — essentially even, a ~$530K swing.**
Deployed system, cold-snap value captured	**+9.8% → +11.4% — better, not worse.**
Winter Storm Uri (deployed, storage engaged)	**+22.0% → +18.9% — the tail is still covered, by storage.**
Uri on OGT baseload alone (no storage)	**+7.9% → +4.1% — the deliberate trade (see below).**

> **The one honest trade-off:** buying leaner on OGT means less baseload standing in front of a surprise cold snap on those towns. That is exactly the risk your schedulers accept too — because on OGT the right tail hedge is not over-buying baseload every month, it is **storage**. Where storage exists (Southern Star) the Uri number barely moves. This is the same conclusion the packet reached: **the ONEOK Gas Storage question is the next fix**, worth the most on the big towns like Pryor Creek. How lean to buy is a dial we set with you.

Before/after on real published prices; deployed figures from the pooled backtest with member storage engaged. Model policy v0.7.0-ogt-anchor.

The demand side — the growth-town fix

Why the biggest misses are growing towns, and the fix now built for them. The other half of every buy: not the price, but how much a town burns.

The combined table's remaining gap — after the OGT fix — sits on the **fast-growing towns** (Pryor Creek, Tuttle). The reason is simple and fixable: the model forecasts a town's use from **its own history**, and a growing town's next winter **is not in its history**. A new plant or a new industrial customer is a fact the **schedulers know** and the meters have not seen yet — so the model trails the ramp and buys as if last year's town is the one it is serving.

The fix — load-event tickets, now built. A scheduler records "**+X per day** (or per cold-degree) from this date, **because Y**" and the forecast uses it immediately. It is point-in-time (it only affects decisions made after it is entered) and self-fading (it eases off over ~270 days as real usage absorbs the new load). A new **growth-watch** also flags towns whose weather-adjusted load is drifting and pre-fills a ticket — so the gap is caught, not found in hindsight.

Does it work? Tuttle's ramp winter, with the ticket vs. without

Tuttle, Nov 2024 – Apr 2025	Scheduler cost	Model cost	Model vs scheduler
Model **blind to the ramp** (no ticket)	$336,958	$391,752	−$54,794
Model **told about the ramp** (one ticket)	$336,958	$365,552	−$28,594
Improvement from the ticket	–	–	+$26,200

One piece of the schedulers' knowledge cut Tuttle's loss nearly in half — $26,200 saved in the winter the load stepped up. That is the demand-side fix in one number.

Growth-watch — who the model is trailing now

Weather-adjusted cold-day load, this year vs. last (the mild winter is normalized out, so this is real load change, not weather).

Town	Load growth, year over year	Covered?
Pryor Creek	+31%	no ticket
Cashion	+19%	no ticket
Jones	+17%	no ticket
Minco	+17%	no ticket
Tuttle	+16%	ticket active

Pryor Creek — our single largest miss — is growing fastest and carries no ticket yet. That is the top demand-side action, and the schedulers are the ones who know the "because."

A ticket is forward-looking: it helps while a town is ramping, then fades as the meters catch up — which is exactly when a scheduler would enter one. Measured on real published prices under model v0.7.0.

Plain-language glossary

The dozen terms that matter, in the order they come up.

Term	What it means here
Unit (MMBtu / Dth)	The standard measure of gas energy. A small town like Ripley burns 20–150 a day; a big one like Pryor Creek, 1,000–5,000. MMBtu and dekatherm are interchangeable for our purposes.
Baseload	Gas bought once, before the month starts, at the monthly price — the same amount every day, like a standing order.
Monthly price (FOM / "first of month")	The published index price at which baseload is bought, set at the start of each month (Inside FERC). The coalition pays index plus a small contracted adder.
Daily price (GDD / "Gas Daily")	The published price for gas bought day-by-day. Usually close to the monthly price — except in cold snaps, when it can be many times higher.
Panic price	A first-of-month that prints far above its normal range (February's was more than double). It usually reverts — so committing a full month of baseload to it is the trap this packet keeps returning to.
Storage	An on-system account: inject gas when it is cheap, withdraw on cold days instead of buying at a spike. It lets the model size baseload lean without fear of being caught short — the missing tool on OGT.
Pooling	A paper meeting-point where the coalition's towns' gas is aggregated and can be moved between member towns at no charge — the cheapest fix for one town long and another short.
MDQ	Maximum Daily Quantity — the contractual ceiling on how much can be delivered to a town per day.
Sell-back	When a town is long, the unused baseload is sold back — usually at the lower daily price, never at a profit. Over-buying a warm month loses exactly this spread.
Tail risk (CVaR)	Our planning yardstick: the average cost of the worst few winters in the replay, not the typical one. The number we refuse to let get big, even at a small premium in normal months.
Sealed clock / "no peeking"	The rule that makes the test honest: the model decides using only records dated before the decision day, and the winters it weighs never include the one that actually happened.
Decision dossier	The two-document record behind every recommendation: a **Data** page (pure evidence) and an **Analysis** page (the AI analyst's reasoning, machine-checked so every fact it cites exists on the Data page).

Where we need the schedulers — and OMNGC

The three towns above each pointed at a place your knowledge closes the gap. These are those, made concrete.

1. The OGT storage & pooling picture — the biggest lever. Every OGT town lost this winter for the same reason: no storage, no confirmed pooling. Two questions: is on-system ONEOK Gas Storage worth pursuing for the big OGT towns (Pryor Creek, Tuttle), and can we get the OGT transport and pooling agreements? OGT's public statement posts no tolerance, penalties, or deadlines — for the coalition's largest group of towns, the contract IS the rulebook, and we are working from memory of it.

2. The panic-month rule of thumb. On February's panic price the schedulers bought lean and were right — on Ripley and Pryor Creek both. What is the heuristic? How far above normal does a first-of-month have to print before you hold back, and by how much? That judgment is the single highest-value thing we can encode.

3. The sell-back and cold-day terms — and who trues up mid-month. The buy-ahead answer is most sensitive to the real sell-back price and cold-day purchase premium, which today are flagged placeholders. And neither the Southern Star nor the Panhandle tariff contains a mid-month true-up, so the one the schedulers describe must come from OGT, Enable, or a supplier — which?

Appendices: A — Pipeline rules summary (the four systems' balancing, penalty, pooling and storage rules, verified against the posted tariffs). B — Ripley February 2027 decision dossier (the same machinery pointed at the hardest month ahead). C — Ripley December 2026 dossier (a mild month — what cold-snap insurance costs and why the policy still buys it). Operational guidance, not legal or trading advice.

Appendix A

Pipeline rules — working summary

Verified against the posted tariffs, June 2026.

Pipeline Tariff Mechanics — Working Summary

Prepared for OMNGC · June 12, 2026 · Dekacern
Sources: live tariff postings of Southern Star Central and Panhandle Eastern (every claim verified against the posted tariff text), ONEOK's posted OGT Statement of Operating Conditions (eff. Sep 1, 2024), and Energy Transfer operational notices. Verification status is marked on every section.

Why this matters: these are the rules that price every imbalance, every cold-snap shortfall, and every missed nomination across the coalition's four supply pipelines. They are now loaded into Dekacern's per-pipeline ruleset registry, where the decision engine reads them. Three items need OMNGC's help to finish — listed at the end.

Southern Star Central — fully verified from the posted tariff

Mechanic	Terms
Balancing	Monthly. Imbalances may be resolved through the END of the FOLLOWING month by: trading with other shippers in the same area, **netting into your Southern Star storage account**, adjusting nominations, or cash-out. GT&C §9.7
Cash-out tolerance	Greater of 1,000 Dth or ±5% of actual deliveries. Beyond it, tiered: pipeline buys your excess at 0.7×/0.6×/0.5× of the Platts Gas Daily Southern Star index (5–10% / 10–15% / over 15%); you buy back shortfalls at 1.3×/1.4×/1.5×. GT&C §9.7(c), Sheets 244–245
Nomination cycles	Standard NAESB clocks (Central time): Timely 1:00 pm day-ahead · Evening 6:00 pm · Intraday-1 10:00 am · Intraday-2 2:30 pm · Intraday-3 7:00 pm (no bumping). GT&C §9.1(e)
OFO penalties	Standard OFO: greater of $5.00/Dth or 2.5× index. Emergency OFO: greater of **$10.00/Dth or 5× index**, per Dth per day. Issued by noon, normally effective the second gas day. GT&C §10.1/§10.3
Pooling	Formal Pooling Service (paper pool points): **transfers between pool members are permitted, with no transport charge and no fuel** on pooled quantities. Oklahoma pools include Oklahoma-Other, South Edmond, Edmond-Blackwell, Straight-Blackwell, Canadian-Blackwell. Rate Schedule PS §3(a)
Storage	On-system storage (the no-notice TSS service bundles transport + storage). Injection season Apr–Oct, withdrawal Nov–Mar; capacity = 33× max daily withdrawal; **injection rights ratchet down as inventory fills** (0.75% of capacity/day below 62.5% full, stepping to 0.25%/day above 87.5%) — this is why a deep winter draw takes most of a season to refill. FSS Rate Schedule §3
Park & loan	Available (PLS), daily commodity up to ~$0.29/Dth. A short-term imbalance-parking alternative.
Fuel retention	**Two posted sheet vintages conflict (storage injection 3.67% vs 3.24%) — we will confirm the live tracker value before it enters any cost calculation.**

Panhandle Eastern (PEPL) — balancing verified; cycle clocks NAESB-standard (assumed)

Mechanic	Terms
Monthly tolerance	Maximum Accumulated Imbalance = greater of 1.5× contract MDQ or **1,000 Dt** — the "±1,000 units" your schedulers know is confirmed, in dekatherms, as the floor of this monthly formula (not a daily band). Carried without charge up to that quantity. GT&C §12.11(a)
Cash-out	Tiered on the NGW Mid-Continent (Panhandle) monthly average: excess gas bought from you at 0.9× down to 0.5×; shortfalls bought by you at 1.1× up to 1.5× (tiers at 5/10/15/20%). GT&C §12.11(a)(1)/(2)
Imbalance trading	

	Post-month: positions posted by the 9th business day, **tradable with other shippers through at least the 17th business day** — usually the cheapest exit. GT&C §12.11(d)(2)
Daily scheduling	Separate from the monthly band: daily deliveries may vary from scheduled by 10% or 100 Dt (whichever greater) at the delivery point, with a location-level safe harbor. GT&C §12.11(h)(1)
OFO penalties	Notice ordinarily by 10:30 am the day before. Tolerance cut to 5%; penalties = greater of 2× the highest of three Gas Daily indices or tiers of **$25 / $50 / $100 / $200 per Dt** as the deviation grows. GT&C §12.17(d)–(f)
Mid-month true-up	**None in this tariff (see open items).**

OGT — ONEOK Gas Transportation — operating statement extracted; the contract is the ruleset

ONEOK's posted Statement of Operating Conditions (Section 311 service, eff. Sep 1, 2024) contains **no published tolerance band, no cash-out schedule, no penalty rates, and no fixed nomination clocks**. It requires "commercially reasonable efforts… as near to zero imbalance as practicable," passes through any upstream/downstream transporter penalties to the customer, and reserves the right to set nomination deadlines per "common industry practices." Gas day 9:00 am Central.

Implication: the 3% tolerance and pooling-with-member-transfers your schedulers work with are **contractual** — they live in the coalition's own OGT transport/pooling agreements, not in any public document. Those agreements are the missing source of truth for the largest group of coalition towns.

EGT — Enable Gas Transmission — tariff text pending; standing alert in force

The tariff (FERC-filed; balancing in GT&C §20, cash-out mechanism in §8) sits behind Energy Transfer's portal and is still being obtained. One finding is operational today:

> **Standing operational alert since December 1, 2025 (Critical Notice 6224):** EGT is providing **no tolerance for short imbalance positions** and is not scheduling long-imbalance paybacks. For Roland, Granite, and Hulbert this means a short day currently has no tariff cushion at all — under-supply on EGT is materially riskier than the same shortfall on Southern Star or PEPL until this alert lifts.

What we need from OMNGC

> **1. Copies of the OGT transport and pooling agreements** (and the SWE pooling arrangement, if separate). For OGT, the contract is the entire ruleset — tolerance, pooling rights, and deadlines all live there.

> **2. Which counterparty performs the mid-month true-up?** Neither the Southern Star nor the PEPL tariff contains one — so the mid-month true-up the schedulers described must come from OGT, EGT, or a bilateral supplier arrangement. Knowing which one changes how long an imbalance can safely ride.

> **3. Confirmation items:** Copan's June price of $3.90 (vs. the $2.37 Southern Star group price); the OGT/ONG blended-rate worksheet (~$2.745); whether "Our Price" in the monthly email is OMNGC's cost from the supplier or the towns' rate.

Prepared by Dekacern from primary sources: Southern Star Central Gas Pipeline FERC Gas Tariff (csimain.southernstar.com, sheets current as posted June 2026); Panhandle Eastern Pipe Line FERC Gas Tariff (peplmessenger.energytransfer.com, GT&C eff. Nov 2021 as currently posted); ONEOK Gas Transportation Statement of Operating Conditions eff. Sep 1, 2024; Energy Transfer EGT operational notices. Tariff provisions change by filing — values should be reconfirmed before contractual reliance. This summary is operational guidance, not legal advice.

Appendix B

Ripley — February 2027 decision dossier

The hardest month ahead: evidence page first, then the verified analysis.

Decision Data — D6 Baseload Sizing

Ripley · plan month 2027-02-01 · hub ogt · pipeline OGT
record b956dac1-1329-4719-a539-361ca88bdce2 · issued 2026-07-01T04:41:38.183122+00:00 · engine engine-v0.5.0 · model demand-v0.4.0 · DCD sha256 a7d71efbfc476b10…

Suggested baseload: 106.9 MMBtu/day
expected cost $25,977.98 · CVAR95 $243,955.22 · worst scenario year 2021 ($243,955.22)

Alternatives considered

Q	E[cost]	CVAR95	why not chosen
106.9	25,977.98	243,955.22	is the chosen suggestion
42.0	63,811.33	830,740.73	last year's average repeated; scores +312,309 vs chosen under the policy objective
0.0	98,999.83	1,348,321.08	all-daily exposure: every cold day bought at GDD

Binding constraints & headroom

- **mdq** = 107.0 — suggestion is capped by contract MDQ

What the engine weighed

- 12 joint weather+price scenario years (2015–2026; cold-snap demand/price coupling preserved; recency half-life 3.0y)
- FOM anchor 4.016 $/MMBtu for Feb 2027
- swing premium x1.05 mild / x1.3 on HDD>=20 days; sellback recovery min(0.85xGDD, FOM) — no-profit rule (A22/A15 confirm pending)
- worst scenario year 2021
- balancing band: OGT 3% CONTRACTUAL (scheduler-reported) — UPDATE THIS ROW when the transport/pooling agreements arrive

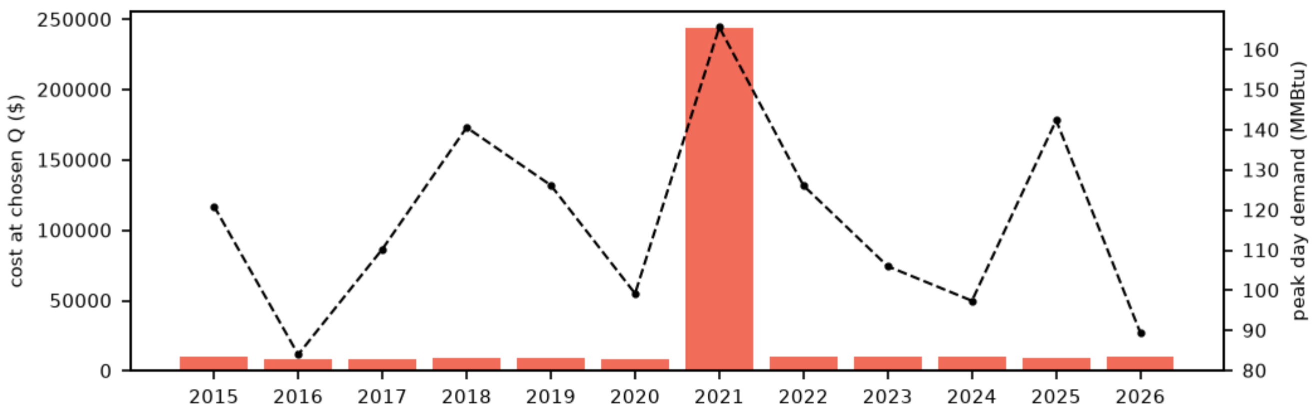
Contract terms — Ripley

counterparty	type	via	MDQ	price formula
Southwest Energy, L.P.	supply	direct	107.0	{"adder": 0.255}
Southwest Energy, L.P.	supply	direct	—	{"adder": 0.05, "index": "IF"}

Scenario set (joint weather + price years)

year	weight	avg demand	peak day	avg GDD $	cost at chosen Q
2015	0.0173	79.9	121.0	3.887	9,888.8
2016	0.0218	49.2	84.0	3.392	8,139.8
2017	0.0275	47.0	110.3	3.409	7,980.34
2018	0.0347	66.4	140.6	2.865	9,700.26
2019	0.0437	72.8	126.2	3.514	9,609.08
2020	0.055	64.6	99.2	4.211	8,472.45
2021	0.0693	89.1	165.6	205.403	243,955.22
2022	0.0873	73.6	126.1	2.331	10,454.16

2023	0.11	64.2	106.0	2.377	9,990.87
2024	0.1386	48.1	97.4	1.797	9,927.78
2025	0.1747	72.5	142.4	4.08	9,196.64
2026	0.2201	42.0	89.4	1.281	10,378.38



Model inputs

demand model	demand-v0.4.0 — base 0.0 MMBtu/d, slope 2.3453 per HDD, cold-day skill vs naive 0.44551212953018904
FOM anchor	$4.016 /MMBtu
MDQ	107.0
risk policy	v0.6.0-panic-haircut — objective (1-0.5)*E + 0.5*CVaR95

Decision Analysis — D6 Baseload Sizing

Ripley · plan month 2027-02-01 · record b956dac1-1329-4719-a539-361ca88bdce2 · analyst model claude-opus-4-8 · verification: **VERIFIED** (26 citations checked)

This page is the analyst model's interpretation of the Decision Data document. Facts live there; reasoning lives here.

Assessment

When considering that Ripley's baseload demand runs 42–89 MMBtu/day in normal years but spikes to a 165.6 MMBtu/day peak in the 2021-style cold snap, that the firm supply contract caps you at 107 MMBtu/day MDQ, and that the policy weights the tail (CVaR95) at 50% against expected cost, locking in the near-maximum 106.9 MMBtu/day of firm supply seems the right way to go. It buys the cheapest firm gas you can (the 0.255 adder contract) up to the contractual ceiling, which slashes the expensive swing/GDD purchases you'd otherwise face on cold days. The chosen plan carries an expected cost of ~$25,978 and a tail (CVaR95) of ~$243,955 — dramatically better than the two alternatives (repeating last year's 42/day average scores +312,309 worse, and buying nothing firm blows the tail out to $1.35M).

Key considerations

- The suggestion of 106.9 MMBtu/day is capped by the contract MDQ of 107.0 — you are essentially maxing out firm supply, with only 0.1 MMBtu/day of headroom left.
- Only one supply contract has a usable MDQ: Southwest Energy's 107.0/day at a 0.255 adder. The second Southwest contract (index IF, 0.05 adder) has a null MDQ, so it cannot be relied on for firm volume in this plan.
- The tail is driven almost entirely by scenario year 2021 (gdd_avg 205.4 vs ~1.3–4.2 in every other year, demand peak 165.6): its cost at the chosen quantity is $243,955 — ~24x any other year — and it carries a 6.93% weight.
- The policy objective (1-0.5)*E + 0.5*CVaR95 is deliberately tail-focused; at 50% tail weight, buying max firm supply beats cheaper-on-average alternatives because it caps how much cold-day gas is bought at premium swing/GDD prices.
- Against alternatives: last-year-average (42/day) scores +312,309 worse under the policy; all-daily exposure (0 firm) pushes worst_cost to $1,348,321. Firm max is the clear tail-minimizer.
- FOM anchor for Feb 2027 is 4.016 $/MMBtu; swing premium is x1.05 mild and x1.3 on cold (HDD>=20) days, with no-profit sellback at 0.85xGDD floor.

Tail exposure

The worst case for Ripley is a repeat of the 2021 cold snap: gdd_avg 205.4 and a demand peak of 165.6 MMBtu/day against a firm ceiling of only 107. On those days you are short ~58 MMBtu/day of firm supply and must cover it with swing (x1.3 premium) or daily GDD purchases — that is the entire source of the $243,955 CVaR95/worst_cost figure. The suggestion handles this as well as the contract allows by buying every available firm MMBtu (106.9 of 107 MDQ); there is no cheaper hedge available inside this contract set. The residual tail is structural — it comes from the MDQ being below peak demand, not from an under-buy. Note the second Southwest contract's null MDQ means no additional firm capacity is modeled to blunt this.

Stress test — what breaks this

Three things would break or worsen this suggestion. (1) The balancing band is flagged as OGT 3% CONTRACTUAL, scheduler-reported, with an explicit 'UPDATE THIS ROW when the transport/pooling agreements arrive' — if the real band is tighter, cold-day imbalance penalties could push the tail above $243,955. (2) The swing/sellback and no-profit rules are noted as 'A22/A15 confirm pending,' so the premium economics feeding the tail cost are not fully confirmed. (3) The 2021 tail relies on a single scenario year at 6.93% weight; with recency half-life 3.0y the model leans on recent mild years (2024/2026 gdd ~1.3–1.8), so if winters trend colder the true tail probability is understated. Watch: any winter where forecast HDD>=20 stacks multiple days, since you're already at MDQ with no firm headroom.

What would change this decision

- A confirmed MDQ on the second Southwest Energy contract (currently null) that adds firm capacity above 107/day — that would directly cut the 2021 tail by covering more of the 165.6 peak.
- Updated balancing band from the actual transport/pooling agreements replacing the placeholder 3% contractual row — a tighter band would raise imbalance risk and could shift the quantity.
- Confirmation of the A22/A15 swing-premium and no-profit sellback rules; if the premium multipliers or sellback floor change, the tail cost and thus the CVaR-driven quantity could move.
- A change in policy tail_weight away from 0.50 — a lower tail weight would favor cheaper-on-average, lower-firm quantities.
- Colder demand forecasts or a longer recency half-life that raises the probability weight on 2021-type years.

Citations (all verified against the DCD)

- `engine.suggestion.q_mmbtu_day` ✓
- `engine.suggestion.expected_cost` ✓
- `engine.suggestion.cvar95` ✓
- `engine.suggestion.worst_cost` ✓
- `engine.suggestion.worst_scenario_year` ✓
- `engine.scores.objective` ✓
- `engine.scores.score` ✓
- `engine.rationale.binding_constraints` ✓
- `engine.rationale.headroom.mdq_mmbtu_day` ✓
- `engine.rationale.considered` ✓
- `engine.alternatives` ✓
- `engine.scenario_table` ✓
- `inputs.mdq` ✓
- `inputs.terms` ✓
- `inputs.fom_anchor` ✓
- `inputs.risk_policy.tail_weight` ✓
- `inputs.risk_policy.coverage_target` ✓
- `inputs.risk_policy.params.swing_premium_cold` ✓
- `inputs.risk_policy.params.swing_premium_mild` ✓
- `inputs.risk_policy.params.cold_hdd` ✓
- `inputs.risk_policy.params.no_profit_sellback` ✓
- `inputs.risk_policy.params.scenario_half_life_years` ✓
- `inputs.risk_policy.salvage_assumption` ✓
- `scope.town` ✓
- `scope.hub` ✓
- `plan_month` ✓

Appendix C

Ripley — December 2026 decision dossier

A mild month: what cold-snap insurance costs and why the policy still buys it.

Decision Data — D6 Baseload Sizing

Ripley · plan month 2026-12-01 · hub ogt · pipeline OGT
record c9741495-cd00-448c-b751-bb5752e17f4e · issued 2026-07-01T04:41:29.852604+00:00 · engine engine-v0.5.0 · model demand-v0.4.0 · DCD sha256 2d53a42508e58869...

Suggested baseload: 62.0 MMBtu/day
expected cost $7,056.61 · CVAR95 $8,242.17 · worst scenario year 2016 ($8,458.77)

Alternatives considered

Q	E[cost]	CVAR95	why not chosen
37.8	6,762.61	9,150.72	minimizes expected cost but carries CVaR +909 vs chosen — tail exposure the policy refuses
56.6	6,876.14	8,444.91	last year's average repeated; scores +11 vs chosen under the policy objective
0.0	6,786.52	10,569.86	all-daily exposure: every cold day bought at GDD

Binding constraints & headroom

- none — interior optimum

What the engine weighed

- 12 joint weather+price scenario years (2014–2025; cold-snap demand/price coupling preserved; recency half-life 3.0y)
- FOM anchor 3.817 $/MMBtu for Dec 2026
- swing premium x1.05 mild / x1.3 on HDD>=20 days; sellback recovery min(0.85xGDD, FOM) — no-profit rule (A22/A15 confirm pending)
- worst scenario year 2016
- balancing band: OGT 3% CONTRACTUAL (scheduler-reported) — UPDATE THIS ROW when the transport/pooling agreements arrive

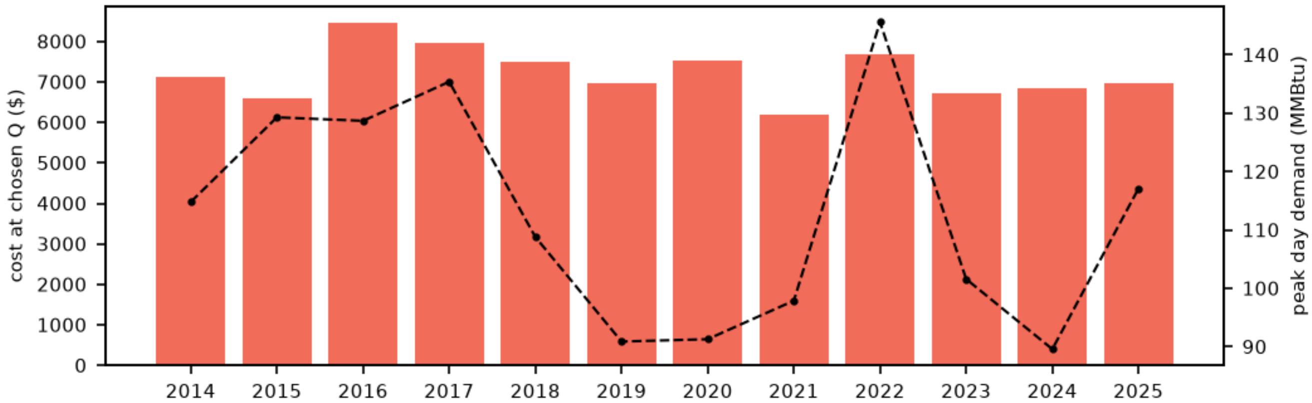
Contract terms — Ripley

counterparty	type	via	MDQ	price formula
Southwest Energy, L.P.	supply	direct	107.0	{"adder": 0.255}
Southwest Energy, L.P.	supply	direct	—	{"adder": 0.05, "index": "IF"}

Scenario set (joint weather + price years)

year	weight	avg demand	peak day	avg GDD $	cost at chosen Q
2014	0.0173	59.2	114.8	2.895	7,114.41
2015	0.0218	52.5	129.3	3.289	6,608.71
2016	0.0275	68.9	128.7	4.304	8,458.77
2017	0.0347	67.2	135.4	3.334	7,977.31
2018	0.0437	63.5	108.8	3.222	7,490.98
2019	0.055	57.9	90.9	3.495	6,971.08
2020	0.0693	63.9	91.3	3.433	7,540.21
2021	0.0873	38.8	97.9	2.236	6,186.61
2022	0.11	65.2	145.6	3.093	7,673.78

2023	0.1386	53.0	101.6	2.918	6,722.97
2024	0.1747	54.6	89.6	2.714	6,856.89
2025	0.2201	56.6	117.1	2.777	6,964.45



Model inputs

demand model	demand-v0.4.0 — base 0.0 MMBtu/d, slope 2.3453 per HDD, cold-day skill vs naive 0.44551212953018904
FOM anchor	$3.817 /MMBtu
MDQ	107.0
risk policy	v0.6.0-panic-haircut — objective (1-0.5)*E + 0.5*CVaR95

Decision Analysis — D6 Baseload Sizing

Ripley · plan month 2026-12-01 · record c9741495-cd00-448c-b751-bb5752e17f4e · analyst model claude-opus-4-8 · verification: **VERIFIED** (26 citations checked)

This page is the analyst model's interpretation of the Decision Data document. Facts live there; reasoning lives here.

Assessment

When considering that Ripley's December demand can spike hard (peak demand up to 145.6 MMBtu/day in 2022 and averaging near 69 in the worst year, 2016), that the policy weights the tail heavily (50/50 blend of expected cost and CVaR95), and that swing gas gets expensive on cold days (x1.3 premium above HDD>=20), buying 62.0 MMBtu/day of baseload seems the right way to go. It doesn't chase the lowest expected cost — it deliberately pre-buys enough to blunt the tail. This is why it beats the expected-cost-minimizing alternative (37.8/day) that would have carried CVaR of 9,150.72 versus the chosen 8,242.17 — roughly 900 more tail exposure the policy refuses to take.

Key considerations

- Objective is tail-focused: score = (1-0.5)*E + 0.5*CVaR95, so the engine trades higher expected cost for lower tail cost by design. Chosen expected cost is 7,056.61 vs the cheaper alt's 6,762.61 — about 294 more on average — in exchange for ~908 less CVaR.
- The chosen 62.0/day sits comfortably under the 107.0 MDQ supply contract, leaving 45.0 MMBtu/day of headroom for swing/peaking days.
- Ripley demand is volatile: worst-year (2016) average demand 68.9 exceeds the 62.0 baseload, and demand peaks reach 145.6 (2022), so daily swing purchases are still expected on cold days.
- Recency-weighted scenarios (half-life 3.0y) put most weight on recent, milder years — 2025 gets 0.2201 and 2024 0.1747 — which pulls expected cost down but the CVaR95 still anchors on the cold 2016 tail.
- The all-daily (0/day) alternative is clearly worst: CVaR 10,569.86 and worst cost 11,876.96 because every cold day is bought at GDD. Pre-buying baseload is the whole value here.
- Last-year's-average alternative (56.6/day) is nearly tied, scoring only +11 worse — meaning 62.0 is not a fragile knife-edge pick; a slightly lower baseload performs almost identically.

Tail exposure

The binding worst case across all options is scenario year 2016 (weight 0.0275, gdd_avg 4.304, demand_avg 68.9). At the chosen 62.0/day, the worst-year cost is 8,458.77 and CVaR95 is 8,242.17. Because 2016 average demand (68.9) is above the 62.0 baseload, the tail cost is driven by swing gas bought on cold days at the x1.3 premium. The chosen quantity handles the tail far better than the thin-baseload alternatives: the min-expected-cost pick (37.8/day) blows out to 9,792.96 worst / 9,150.72 CVaR, and going all-daily reaches 11,876.96 worst. So 62.0/day meaningfully compresses the tail without exhausting the 107.0 MDQ.

Stress test — what breaks this

Three things to watch. (1) Policy economics are placeholder/pending — the no-profit sellback and swing premiums are flagged 'A22/A15 confirm pending' in the rationale, so the tail cost math rests on unconfirmed rules; if the real swing premium or sellback recovery differs, the ranking between 62.0 and the 56.6 alternative (only +11 apart) could flip. (2) The balancing band is scheduler-reported (OGT 3% CONTRACTUAL) and explicitly flagged 'UPDATE THIS ROW when the transport/pooling agreements arrive' — the real tolerance could change swing costs. (3) The second supply contract (40a7420b) has mdq_mmbtu_day = null, so only the 107.0 MDQ from the first contract is counted as headroom; if that IF-indexed contract adds capacity or its adder (0.05) matters, the picture shifts. Also note recency weighting leans hard on mild recent years — if December 2026 runs colder than 2023–2025, realized demand can exceed the scenario base.

What would change this decision

- Confirmation or change of the pending policy economics (no_profit_sellback / swing_premium_cold 1.3 / swing_premium_mild 1.05) — flagged A22/A15 pending.
- Arrival of the transport/pooling agreements updating the 3% balancing band that is currently scheduler-reported.
- A firm MDQ for the second Southwest Energy contract (currently null), which would change available headroom.
- A colder-than-scenario December forecast, since recency weighting currently favors mild 2023–2025; note forecast_efficacy is 0.0 so forecasts aren't yet trusted in the model.
- A change to the tail_weight (0.5) in the objective — lowering it would favor the cheaper 37.8/day pick, raising it would push baseload higher.

Citations (all verified against the DCD)

- `engine.suggestion.q_mmbtu_day` ✓
- `engine.suggestion.cvar95` ✓
- `engine.suggestion.worst_cost` ✓
- `engine.suggestion.expected_cost` ✓
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- `inputs.risk_policy.params.tolerance_pct` ✓
- `inputs.risk_policy.params.scenario_half_life_years` ✓
- `inputs.risk_policy.params.forecast_efficacy` ✓
- `inputs.risk_policy.salvage_assumption` ✓
- `scope.town` ✓
- `plan_month` ✓