

The Digest's 2026 Multi-Slide Guide to Modular CCS for Biorefineries

Capture is modular; pore space is not. Local storage and Class VI primacy determine whether ethanol CO₂ can earn 45Q.

Biorefinery CCS has moved from concept to commercial injection

North Dakota ethanol plants have sustained commercial CO₂ injection across multiple years. Their results show that the decisive step is connecting high-purity fermentation CO₂ to permitted pore space—not choosing a different capture skid.

Capture is ready at plant scale

- Fermentation produces a nearly pure CO₂ stream; a reference ethanol plant emits about 0.143 Mt/yr, enabling capture centered on compression and conditioning rather than intensive separation.
- NETL estimates ethanol capture at \$31.8/t versus \$19.0/t for ammonia at similar purity. The roughly 70% premium reflects smaller plant scale; both figures are in December 2018 dollars.
- Red Trail Energy injected about 184,000 tonnes in 2024 and 178,700 tonnes in 2025, according to North Dakota regulator volumes converted to tonnes.
- Blue Flint injected about 188,700 tonnes in 2025. These records establish sustained, site-scale injection, though neither plant's capture rate or installed cost is disclosed.

Pore-space access closes the loop

- The operating chain runs from fermentation CO₂ through compression and conditioning to a local well or pipeline, then a Class VI-permitted storage site and regulator-reported injected tonnes.
- North Dakota's local storage and state Class VI primacy enabled per-plant injection; their results should not be attributed to superior capture design alone.
- Transport and storage add an estimated \$10–40/t. At the high end, this exceeds NETL's \$31.8/t ethanol capture estimate, making the route consequential to project economics.
- Secure geologic storage qualifies for a stated \$85/t 45Q credit, subject to applicable requirements. An unbuilt pipeline cannot deliver injected tonnes, leaving capture capital without that revenue.

Commercial injection at Red Trail and Blue Flint validates site-scale biorefinery CCS where storage is reachable and permitted. For an ethanol plant, the route to pore space—not the modular capture design—determines whether captured CO₂ becomes verified injection eligible for 45Q.

Fermentation CO₂ is nearly pure, putting ethanol far below dilute-source capture costs

Fermentation CO₂ requires much less separation than dilute industrial emissions, making capture comparatively inexpensive. Purity does not determine whether captured CO₂ can reach permitted pore space.

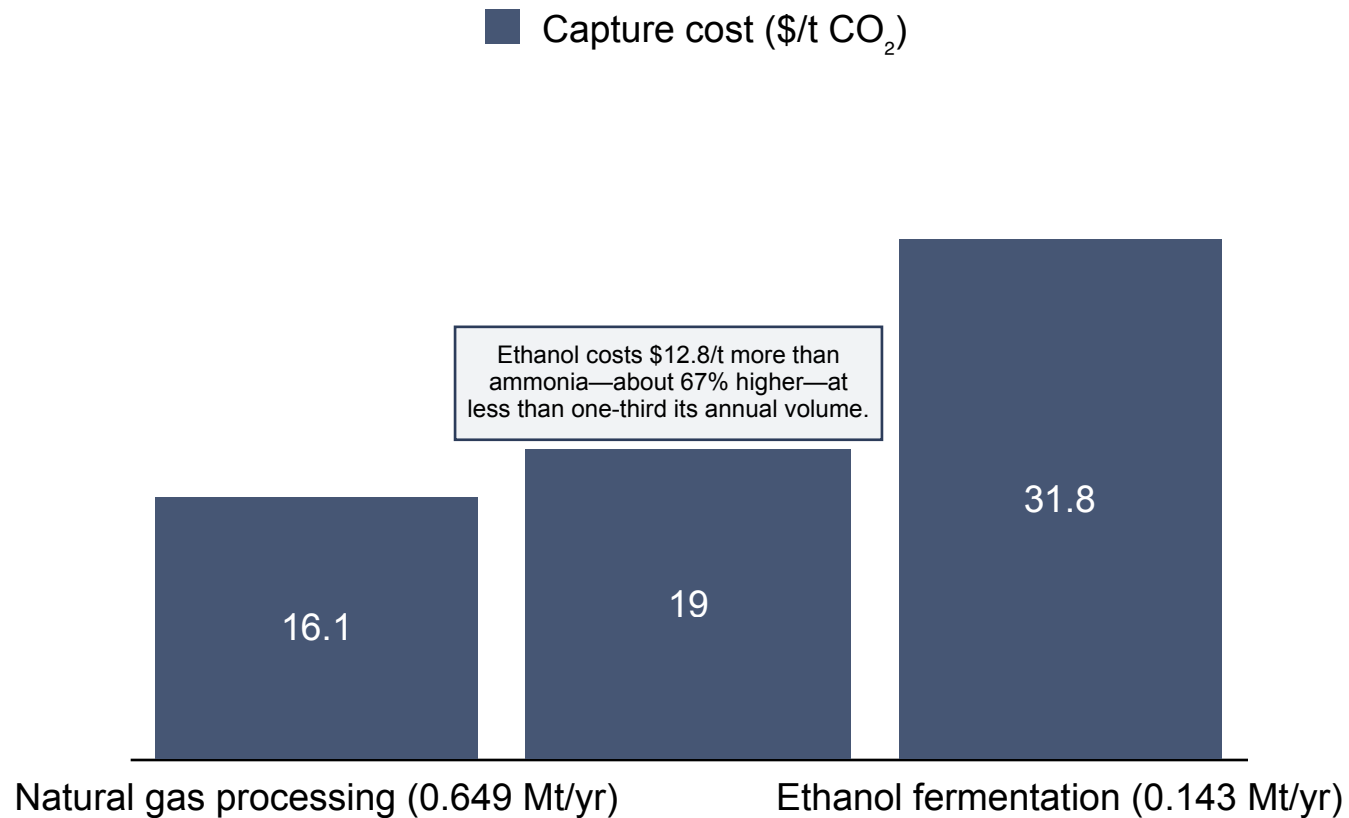
Why fermentation capture costs less

- Fermentation releases a nearly pure CO₂ stream; the NETL ethanol reference plant produces 0.143 Mt/yr. Unlike dilute flue gas, this stream needs little CO₂ separation before compression and conditioning.
- IEA benchmarks put capture from high-concentration streams at \$15–25/t, versus \$40–120/t for dilute streams. These are source-category ranges, not an ethanol-specific quote.
- NETL estimates ethanol capture at \$31.8/t, compared with \$59.9/t for refinery hydrogen and \$62.7/t for cement (December 2018 dollars). Ethanol's smaller scale helps explain why its estimate exceeds the broad high-concentration range.
- High purity makes ethanol a comparatively accessible capture opportunity, but capture cost alone cannot establish a viable CCS project: injected tonnes still require reachable, permitted storage.



At similar purity, ethanol capture still costs about 70% more than ammonia

Greenfield capture cost and reference volume by source (NETL; Dec 2018 dollars)



Purity does not erase the scale penalty

- Ethanol fermentation: \$31.8/t at a reference volume of 0.143 Mt/yr.
- Ammonia: \$19.0/t at 0.486 Mt/yr; ethanol's \$12.8/t premium is approximately 67%.
- Natural gas processing: \$16.1/t at 0.649 Mt/yr, the largest reference volume of the three.
- All costs are NETL greenfield estimates in December 2018 dollars, not current bids or operating-plant costs.
- Compression and electrical escalation could plausibly add 30–45% by 2026; that is an assessment, not a measured update.

Purity does not erase the scale penalty

NETL estimates ethanol fermentation capture at \$31.8/t versus \$19.0/t for ammonia, despite both being high-purity CO₂ sources. Ethanol's smaller reference plant scale is the key distinction in this comparison.

The gap is scale, not chemistry: a \$13-16/t modularity penalty

The observed gap between these high-purity streams is principally a scale penalty, not evidence that ethanol needs fundamentally different separation chemistry. Smaller, replicable plant-scale systems carry higher costs per tonne than larger installations.

**0.143
Mt/yr**

Ethanol scale

NETL's reference ethanol fermentation plant is roughly one-third the size of its ammonia benchmark.

**0.486
Mt/yr**

Ammonia scale

Larger annual CO₂ volume spreads capture-system capital and fixed operating costs across more tonnes.

\$12.8/t

Capture cost gap

NETL estimates \$31.8/t for ethanol versus \$19.0/t for ammonia, both high-purity streams, in December 2018 dollars.

~40%

Ethanol cost share

The \$12.8/t benchmark gap equals 40% of ethanol's \$31.8/t capture cost; the broader \$13–16/t estimate is about 40–50%.

What the evidence supports — and what it doesn't

Supported by cost benchmarks

- NETL estimates ethanol fermentation capture at \$31.8/t, versus \$59.9/t for refinery hydrogen and \$62.7/t for cement (December 2018 dollars).
- IEA benchmarks put high-concentration capture at \$15–25/t and dilute-stream capture at \$40–120/t; ethanol benefits from a nearly pure fermentation stream.
- The relevant high-purity comparison is ammonia: NETL estimates \$19.0/t, roughly 40% below ethanol's \$31.8/t.
- NETL's ethanol estimate assumes 0.143 Mt/yr, versus 0.486 Mt/yr for ammonia; the comparison supports a plant-scale cost penalty, not capture-cost parity.

Not established by the available evidence

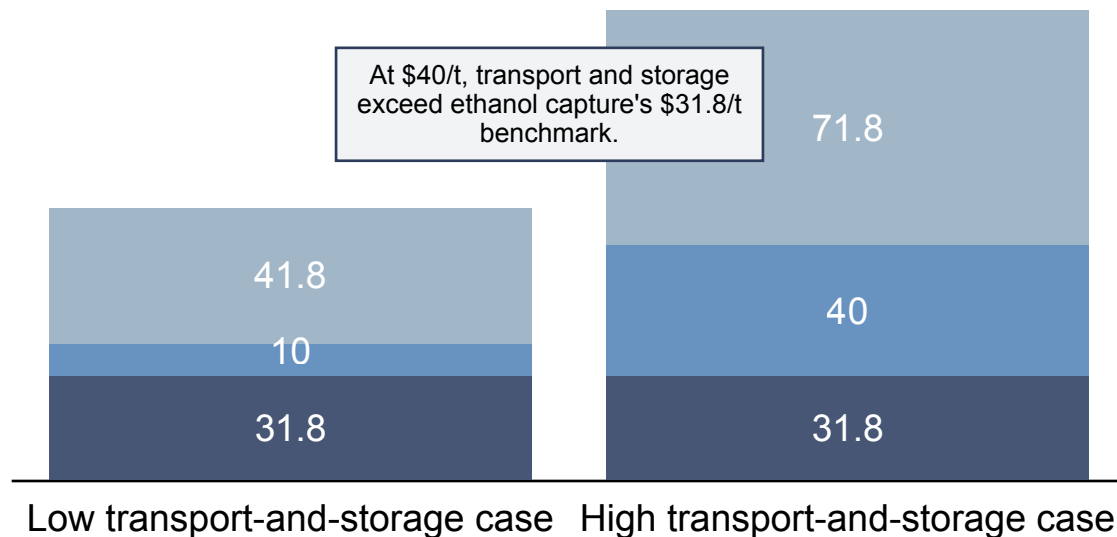
- No cited evidence establishes a “90%+” capture rate for the ethanol projects; do not present it as measured performance.
- “Competitive with conventional capture at refineries” obscures ethanol's higher cost than larger high-purity ammonia capture, despite its advantage over refinery hydrogen.
- Claims that Summit, Wolf or Navigator are deploying modular capture packages lack verified project-status evidence.
- No cited evidence establishes an amine-versus-membrane advantage or confirms Honeywell UOP, Aker or MHI involvement.

Retain the qualified claim that ethanol capture costs less than dilute-source capture, while stating its scale penalty against ammonia. Remove unsupported capture-rate, vendor and project-deployment claims before publication.

Transport and storage can cost more than capture itself

Illustrative ethanol CCS cost stack (\$/t CO₂)

- Illustrative combined cost
- Transport and storage: DOE Liftoff estimate
- Capture: NETL Dec. 2018 benchmark



The downstream cost lever

- NETL estimates ethanol fermentation capture at \$31.8/t CO₂ in December 2018 dollars.
- DOE Liftoff estimates an additional \$10–40/t for transport and storage; the range is not specific to any named plant.
- At the \$40/t upper bound, downstream costs exceed capture by \$8.2/t; illustrative combined cost reaches \$71.8/t.
- Local storage can reduce transport exposure; a remote route requires its own cost and completion assessment.
- Named projects do not disclose route-specific transport-and-storage costs, so the range cannot establish their actual delivered costs.

The downstream cost lever

DOE Liftoff estimates transport and storage at \$10–40 per tonne, in addition to ethanol capture's \$31.8 per tonne NETL benchmark. At \$40 per tonne, the downstream cost exceeds capture, making the route to pore space decisive for delivered cost.

Two competing architectures for getting CO₂ to pore space



Site-scale local injection

Each ethanol plant conditions CO₂ and injects into nearby storage under a Class VI permit; transport is minimal.



Hub-and-spoke pipeline

Plants feed remote storage through a multi-state pipeline; right-of-way and construction gate injection, leaving viability unproven.

Local pore space enables proven site-scale injection; pipeline-dependent capture cannot earn storage credits until the route is complete.

Red Trail and Blue Flint: proof that local storage architecture works

Both plants have sustained regulator-reported injection without a long-distance pipeline. Their records validate site-scale storage where geology and North Dakota's Class VI primacy coincide—not a superior capture design.



North Dakota plants

- Red Trail Energy began CO₂ injection in June 2022.
- Blue Flint began CO₂ injection in October 2023.
- Both pair plant-scale ethanol CO₂ handling with local geologic storage.
- North Dakota holds state Class VI primacy for injection-well permitting.

Deployment test

- A nearly pure fermentation stream is not enough: captured CO₂ must reach permitted pore space before injection and credit generation can begin.
- A remote-storage design would require a completed transport route; these plants instead needed workable storage at or near their sites.
- Nameplate capture capacity cannot establish performance; sustained, regulator-filed injection across calendar years is the relevant test.

Observed injection

- Red Trail injected ~184,000 t in CY2024 and ~178,700 t in CY2025, demonstrating injection continuity across years.
- Its Jan–Jul 2026 volumes annualize to ~236,000 t/yr; cumulative injection reached ~689,000 t over 50 months.
- Blue Flint injected ~188,700 t in CY2025 and reached ~483,500 t cumulatively, providing a second operating example.
- Regulator-reported volumes support the local-storage model; capture rates and full installed costs remain undisclosed.

Summit Carbon Solutions: permitted storage, unbuilt pipeline



The missing connection

- Summit holds permits for three North Dakota CO₂ storage facilities, but the gathering pipeline needed to connect plants to those facilities is not complete.
- Its hub-and-spoke model depends on a continuous route from individual plant capture units through a multi-state pipeline to remote injection sites.
- Pipeline right-of-way and construction are therefore the deployment gate; a permitted storage site alone cannot receive CO₂ from an unconnected plant.
- Until a route operates and tonnes are injected, plant capture capacity does not establish 45Q revenue. Summit's capital cost and capacity figures remain unverified and are excluded.

Summit illustrates the pipeline architecture's central risk: permitted pore space has value only when plants can reach it. Gate capture investment on a completed, usable storage route rather than on storage permits alone.

The gate is a rule: Class VI primacy and EPA review timelines

A storage route needs a Class VI authorization before injection can begin. State primacy and EPA review timelines shape deployment timing more directly than the choice of modular capture equipment.

6

Primacy states

Arizona, Louisiana, North Dakota, Texas, West Virginia and Wyoming administer their own Class VI injection-well programs.

26

EPA applications

Applications were under EPA review as of 22 May 2026, outside the state-administered approval path.

~2 years

EPA review target

EPA targets approximately two years after receiving a complete application; this is a target, not an observed approval time.

Alternative explanation: location, not capture design, explains success

Red Trail and Blue Flint demonstrate sustained injection, not superiority of a particular capture design. Their location above reachable storage in a Class VI primacy state helps explain why they operate while pipeline-dependent projects remain gated by access.

External conditions determine access to storage

- Storage beneath or adjacent to a plant avoids dependence on a long-distance CO₂ pipeline; geology cannot be replicated by ordering another capture unit.
- North Dakota holds Class VI primacy, allowing the state to permit injection wells; Red Trail and Blue Flint operate there.
- Outside primacy states, federal Class VI review applies; EPA's approximately two-year review period is a target for completed applications, not a guaranteed duration.
- An unbuilt pipeline requires right-of-way and construction before remote storage can receive captured CO₂.
- The \$85/t 45Q credit rewards eligible stored tonnes, but its value cannot compensate for a missing injection route.

Plant and operator choices still affect performance

- Nearly pure fermentation CO₂ reduces separation duty, an inherent advantage shared by ethanol plants rather than a distinctive capture design.
- Ethanol's smaller reference volume—0.143 Mt/yr versus ammonia's 0.486 Mt/yr—contributes to a roughly \$13–16/t capture-cost penalty.
- Operators can identify a storage route and advance its Class VI permit before committing to capture equipment.
- Reliable compression, conditioning, injection and monitoring turn an available route into regulator-reported stored tonnes.
- Installed-cost discipline must cover the complete system—including flowline, well and monitoring—not just the capture skid.

What the prize is worth: 45Q revenue at scale

\$85/t

Storage credit

45Q value per eligible tonne securely stored; actual revenue depends on verified injection and tax-credit eligibility.

**180–
250K t**

Annual injection

Illustrative single-plant injection range used to size annual credit revenue, not a guaranteed capture rate.

\$15.3M

Lower annual credit

180,000 eligible injected tonnes multiplied by \$85/t, before project costs and financing.

\$21.3M

Upper annual credit

250,000 eligible injected tonnes multiplied by \$85/t; rounded from \$21.25 million.

At 180,000–250,000 eligible injected tonnes per year, 45Q represents roughly \$15.3–21.3 million in annual gross credits for one plant. Without an operating route to permitted storage, capture capacity produces no injection-based credit.

Stranded capture: capital with no reachable pore space earns nothing



The route determines whether capital earns 45Q

- Red Trail and Blue Flint inject into local North Dakota storage. Their regulator-reported volumes demonstrate an operating route from ethanol plant to pore space—not merely installed capture capacity.
- A pipeline-dependent plant without permitted local storage cannot inject until its connecting pipeline is complete. An installed capture unit alone does not establish 45Q-eligible stored tonnes.
- Summit has three permitted North Dakota storage facilities, but the pipeline to reach them is not complete. Permitted pore space at the destination does not solve the missing connection.
- At \$85 per securely stored tonne, 180,000–250,000 injected tonnes imply roughly \$15.3–21.3 million in annual 45Q credits; without eligible injection, that modeled revenue is zero.
- Before capture FID, secure the storage route and permitting pathway. Treat capture equipment ordered ahead of an unbuilt pipeline as stranded-capital risk.

Storage access must precede capture investment. Underwrite regulator-reported injected tonnes and 45Q eligibility, not a capture unit's nameplate capacity.

Where modular capture belongs — and where it remains unproven



The deployment boundary

- Best fit: a plant compresses and conditions fermentation CO₂, then injects into storage beneath or adjacent to its site; short transport distances limit downstream exposure.
- Class VI authorization remains essential. Six states have primacy; 26 applications were under EPA review as of May 22, 2026. EPA's approximately two-year review period is a target, not an observed average.
- Without reachable local storage, a plant depends on a multi-state pipeline. Permitted storage alone does not establish a working route; completion of the proposed connection remains unconfirmed.
- Smaller ethanol volumes impose a second boundary: NETL estimates \$31.8/t capture at 0.143 Mt/yr, versus \$19.0/t for ammonia at 0.486 Mt/yr—roughly a \$13/t scale penalty in 2018 dollars.

Site-scale capture is supported where storage is local and Class VI authorization is achievable. The pipeline-network alternative remains unproven: do not commit capture capital on the assumption that a future route will connect the plant to pore space.

How strong operators sequence capture and storage

Gate capture FID on a permitted or credible route to pore space. Judge operating performance by verified injected tonnes and a full installed-cost boundary, not capture nameplate or unsupported rates.

Strong execution: prove the route and the tonnes

- Before capture FID, identify the storage site, CO₂ route and Class VI permit or primacy-state application; make route readiness an investment gate.
- Track regulator-filed injected tonnes by calendar year. Red Trail reported ~184,000 t in 2024 and ~178,700 t in 2025, demonstrating continuity beyond nameplate capacity.
- State the installed-cost boundary: compression, conditioning, flowline, injection well and monitoring—not just the capture skid.
- Assign ownership of 45Q accounting and verification; credit revenue depends on eligible, documented storage, not captured tonnes alone.

Weak execution: commit capital before access

- Size or order capture equipment without a named storage route or a credible Class VI permitting path.
- Rely on an unfinished gathering pipeline without secured right-of-way; an available capture unit cannot inject across a missing link.
- Present capacity as “up to” a stated volume rather than reporting actual, regulator-filed injection across successive years.
- Quote capture rates or low costs without measured support or a defined installed-cost boundary; skid-only figures conceal downstream exposure.

Executive takeaway: sequence storage and permit first, capture second

Local storage and a Class VI pathway turn modular ethanol capture into an operating asset. An unbuilt pipeline leaves the same equipment unable to deliver verified injected tonnes.

Back site-scale projects

- Prioritize plants with storage beneath or adjacent to the site and a defined Class VI permit pathway; secure both before capture final investment decision (FID).
- Red Trail and Blue Flint demonstrate sustained, regulator-reported injection in North Dakota, a Class VI primacy state; their results do not establish superior capture design.
- Underwrite annual injected tonnes and 45Q eligibility, not nameplate capture capacity. At 180,000–250,000 t/yr, \$85/t implies approximately \$15.3–21.3 million in annual credits.
- Require an installed-cost boundary covering compression, conditioning, flowline, well and monitoring, plus a named owner for injection reporting and 45Q verification.

Gate pipeline-dependent capital

- Treat capture equipment as stranded-asset risk when storage requires an unfinished pipeline; defer FID until the route and right-of-way are secured.
- Do not infer pipeline-network readiness from storage permits alone: Summit has three permitted North Dakota storage facilities but no completed pipeline connecting them.
- Stress-test delivered economics: transport and storage add an estimated \$10–40/t, potentially exceeding ethanol's \$31.8/t benchmark capture cost (2018 dollars).
- Remove unsupported 90%+ capture-rate claims and unverified pipeline or vendor deployment claims. Evidence supports local site-scale injection; pipeline-hub performance remains unproven.

Approve capture only after the storage route and permitting path are credible. Measure success in regulator-reported injected tonnes eligible for 45Q—not equipment capacity.