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CCUS IN NORTH AMERICA

The Wave Is Coming

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FOCUS

What is the CCUS project landscape in North America? What trends have emerged among operational and planned projects? Which companies are involved across the value chain?

KEY POINTS

- North American CCUS capture capacity will increase sixfold by ~260 MMtpa based on planned projects with announced start dates. The region will go from capturing less than 1% of CO_2 point source emissions in 2021 to 10%. Texas and Alberta lead the pack with over 90 MMtpa of capacity each, addressing roughly 30% and 65% of state/provincial industrial emissions.
- The jump is almost entirely attributable to CCS projects as the industry moves away from a predominately CO_2–EOR capture world. About 80% of CCS projects by capacity will involve upstream and midstream companies due to their expertise in gas treating and processing, transportation and subsurface characterization.
- Supermajors and large-cap companies will dominate the space based on their abilities to deploy large amounts of capital and to handle regulatory, policy and technical risks. XOM surpasses peers with 108 MMtpa of announced CCUS capacity, which includes the Houston CCS Hub with partners CVX and SHEL. CNQ, CVE, MEG, IMO, SU and COP joined forces to form the Oil Sands Pathways project, which could reduce emissions by up 60% in the Fort McMurray/Cold Lake corridor and make oil sands carbon intensity competitive with unconventional L48 barrels.
- Louisiana is best positioned for capacity growth based on leading capture breakevens, subsurface storage capacity and a low CCUS adoption rate. We believe this bodes well for DEN, which operates 98% of the state's CO_2 pipe by length, and TALO, which recently announced its River Bend CCS sequestration project in the Baton Rouge/New Orleans area.
- Conversely, capture costs in California average more than $100/tonne – the highest in the nation – although projects can access up to $240/tonne in incentives between 45Q and the state's Low Carbon Fuel Standard (LCFS) and cap and trade programs. CRC, CVX and AMTX have been the most vocal about plans to develop the technology in California.

- Nearly half of all proposed capacity in North America is attributed to gathering CO_2 emissions from multiple sectors (hub models), followed by point source projects at petroleum and natural gas systems and power plants. The latter group accounts for 60% of CO_2 volumes in the U.S. and Canada, although unattractive retrofit economics justify the low rate of capacity proposals across the sector (amounting to only 2% of associated power generation emissions).
- Natural gas processing plants, ammonia and petrochemical production are the most economic capture subsectors with average breakevens of $23, $30 and $34/tonne. Point source projects in each of these subsectors only represent roughly 1% of total announced capture capacity, presenting opportunities for cost-competitive technology deployment.

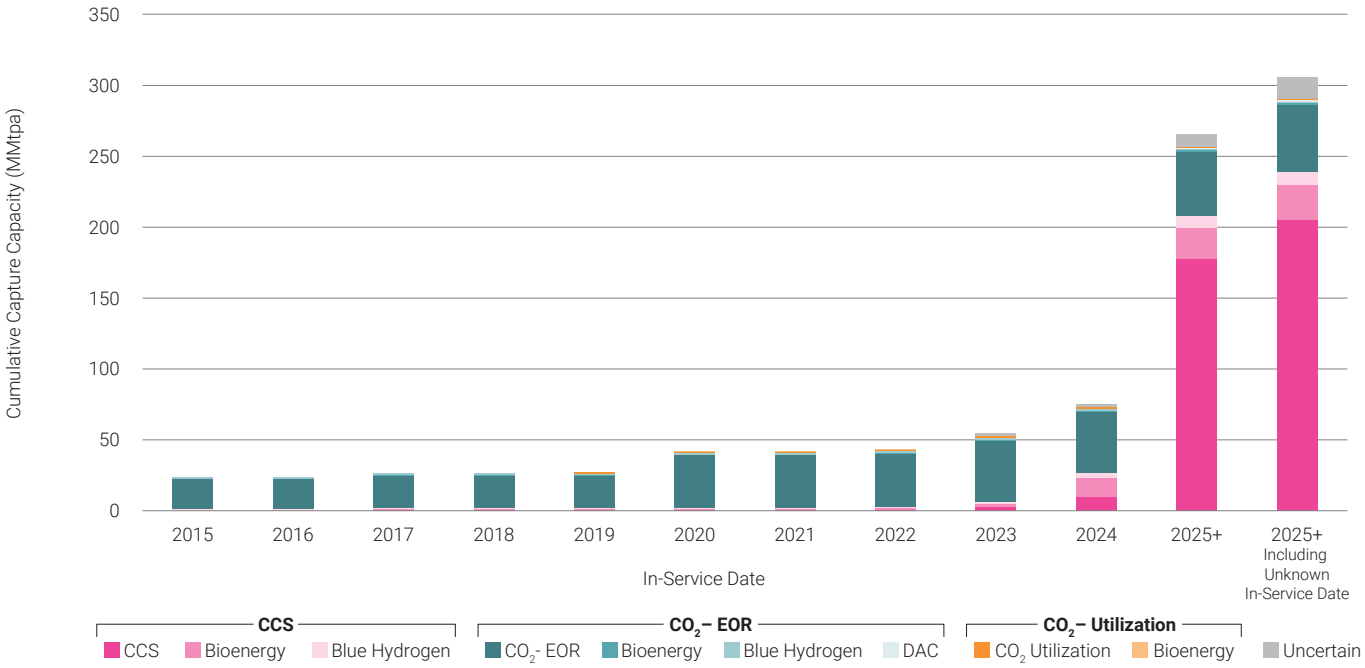
GENERAL

Carbon capture technology has been around for decades, although the deployment of large-scale, integrated CCUS projects is still in its infancy. 2020 marked a pivotal year for carbon storage as interest surged and announced capacity adds started to accelerate for projects with 2025+ in-service dates (**Figure 1**). Operational and planned projects now span multiple geographies, capture sources and CO_2 applications and the list of stakeholders continues to grow. This report summarizes North American CCUS project data disclosed through the end of 2021 and identifies key trends and opportunities for the technology.

NEED TO KNOW

This report only incorporates operational (including pilot) and proposed North American projects with disclosed annual capacity, or annual throughput in the absence of capacity. For projects that span multiple jurisdictions, we classified location according to the storage site. We note that in-service dates are subject to change, especially for projects still in the conceptual phase. For detailed project information, please see the linked spreadsheet available in the Vault.

FIGURE 1 | North American CCUS Capacity Through Time

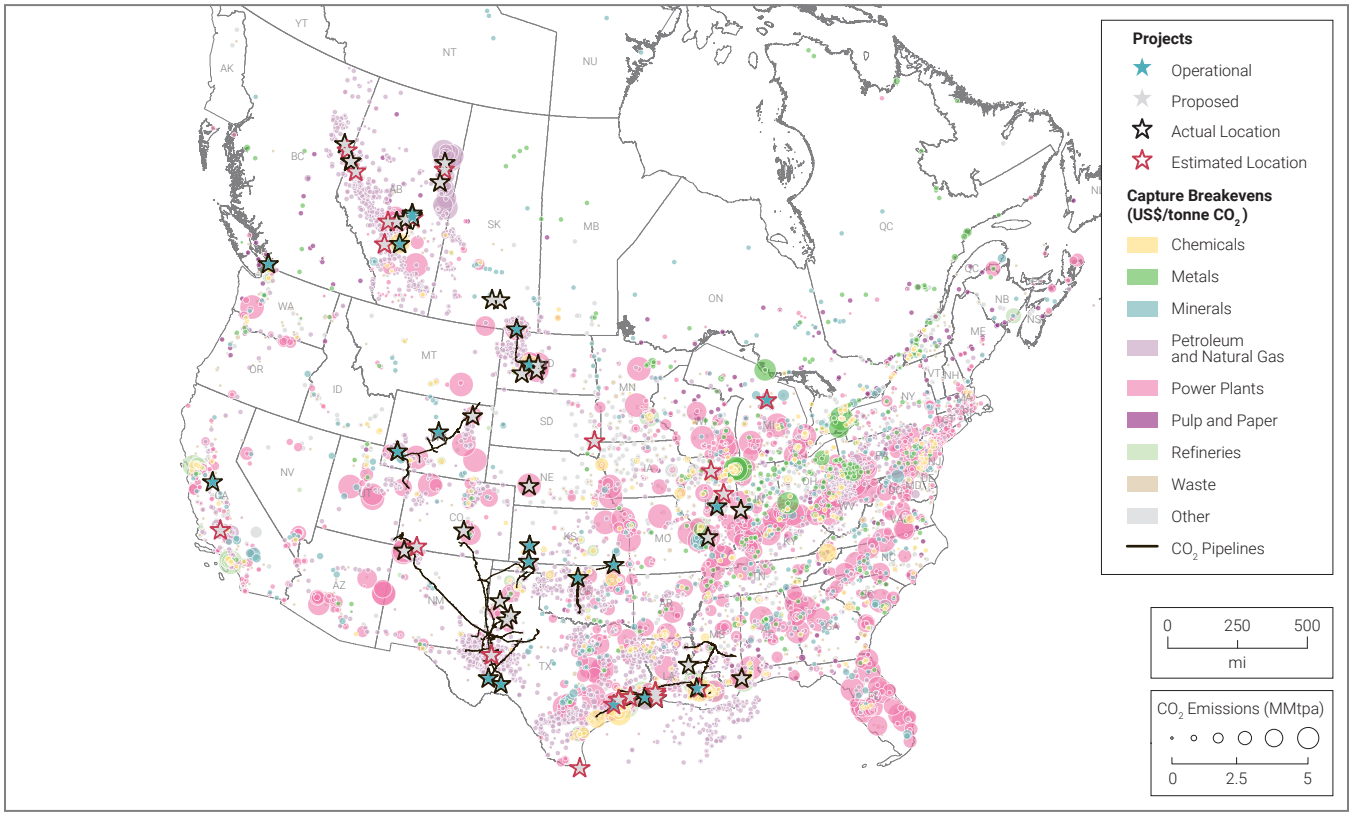


Source | Enverus, Global CCS Institute, company disclosures

PROJECT GEOGRAPHY

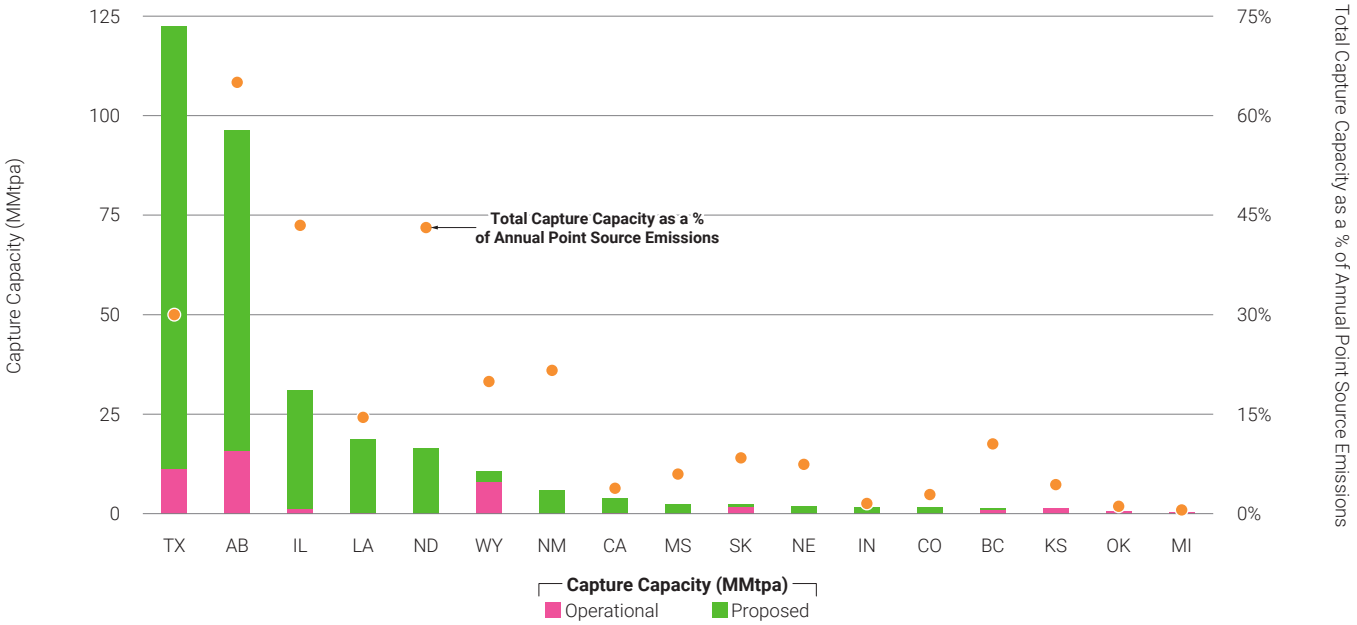
Net zero commitments, strengthening policy and stakeholder capitalism are driving adoption of CCUS technology in both the U.S. and Canada (**Figure 2**). As of the end of 2021, operational and planned projects accounted for 42 and 261 MMtpa of capture capacity, respectively, or less than 1% and 10% of annual CO_2 point source emissions. Texas and Alberta lead the pack with over 90 MMtpa of capacity each, addressing roughly 30% and 65% of regional industrial emissions (**Figure 3**). The latter's outsized uptake is underpinned by multiple sequestration hub proposals, although the province's competitive tenure management process will ultimately determine pore space ownership.

FIGURE 2 | Operational and Proposed CCUS Projects and Existing CO_2 Infrastructure



Source | Enverus ESG Analytics, Global CCS Institute, company disclosures

FIGURE 3 | Operational and Proposed CCUS Capacity by State or Province



Source | Enverus ESG Analytics, Global CCS Institute, company disclosures

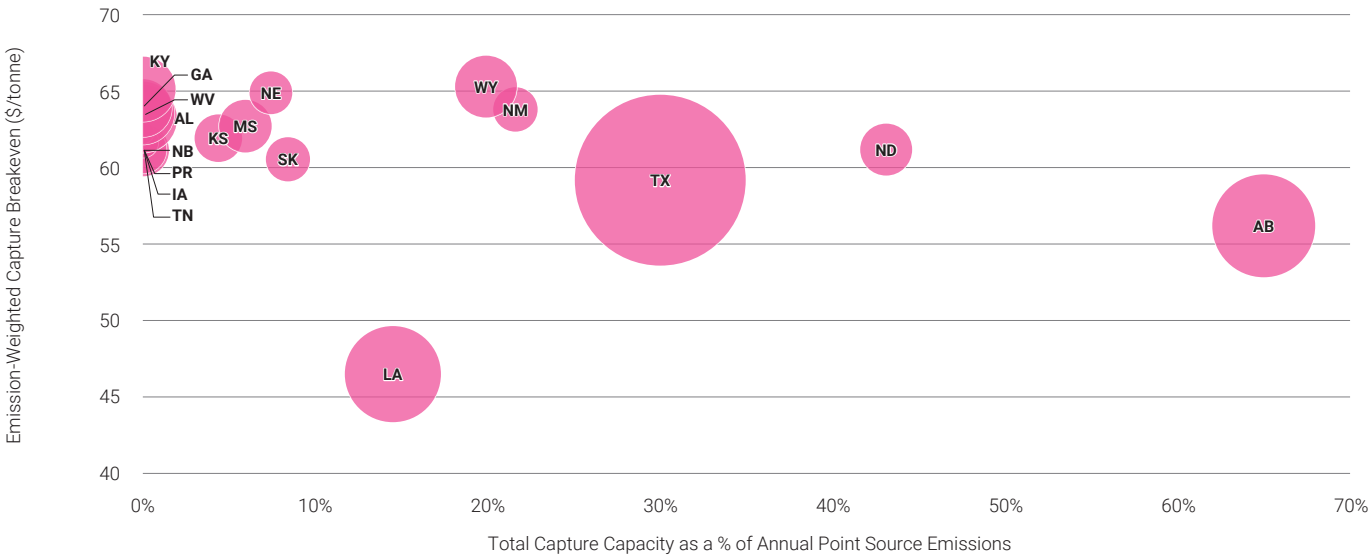
Figure 4 identifies the top 18 states and provinces with the most competitive, yet untapped capture opportunities. Our modeling suggests that Louisiana is best positioned for capacity growth based on leading capture breakevens and a low CCUS adoption rate. The state is also proximate to expansive storage potential in the **Frio sands** and is actively pursuing primacy over the Class VI permit process to expedite carbon monetization opportunities (**Figure 5**). Assuming the 45Q tax credit is raised from $50 to $85/tonne[1] for permanent sequestration, Louisiana is poised to support a wave of profitable carbon capture projects. We believe this bodes well for **DEN**, which operates 98% of the state's CO_2 pipe by length, and TALO, which recently announced its River Bend CCS sequestration project in the Baton Rouge/New Orleans area.

[1]The 45Q tax credit should be shared across the capture, transportation and storage entities.

NEED TO KNOW

Operators must file Class VI permits for wells used to inject CO_2 into deep rock formations for long-term storage. Under the EPA's Underground Injection Control (UIC) Program, states can apply for primary enforcement authority, or primacy, over the implementation of federal permitting programs. As of today, only Wyoming and North Dakota have primacy over Class VI permits instead of the EPA, while Texas and Louisiana have applied. This regulatory change should speed up permit reviews from six to two years or less, allowing 45Q credits to be claimed earlier and incentivizing participation from neighboring emitters.

FIGURE 4 | States and Provinces by CO_2 Capture Potential



Note | Bubbles sized by annual point source emissions.
Source | Enverus ESG Analytics

FIGURE 5 | Key Policy, Regulatory and Economic Considerations in Select States/Provinces

State/ Province	Policy Mechanisms	Class VI Primacy	Pore Space Ownership	Capture Breakeven (US$/tonne)	Capture Capacity vs. Emissions (%)
LA	45Q	Pursuing	Surface Owner	$46	14%
AB	**Carbon tax** escalating to C$170/tonne by 2030, investment tax credit	N/A	Crown	$56	65%
TX	45Q	Pursuing	Surface Owner	$59	30%
ND	45Q	Yes		$61	43%
WY	45Q	Yes		$65	20%
CA	45Q, LCFS, cap and trade	No		$105	4%

Source | Enverus ESG Analytics, Global CCS Institute, company disclosures

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