Green Ammonia: A Low Carbon Solution and Economic Driver for Rural Minnesota

Update to 2023 AURI Report "Securing a Better Future Through the Development of Green Ammonia Fertilizer Pathways"

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About AURI

The Agricultural Utilization Research Institute is a nonprofit whose mission is to accelerate the agricultural economy by empowering expanded uses and markets of agriculturally derived products. It accomplishes this by using science and technology to help develop new uses for agricultural products. It collaborates globally, acts regionally, and is known as an economic catalyst for Minnesota with a focus on bioindustrial products and food. AURI provides a broad range of services, including applied research and development, scientific assistance, and a targeted network across the value chain to foster collaboration. To learn more, visit www.auri.org.

Acknowledgments

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About our research methods

AURI acknowledges the use of generative AI, including large language models (LLMs) as a productivity tool for literature research, synthesis, drafting, and other research-assistance tasks, while all conclusions, calculations, interpretations, and recommendations are originated, reviewed, and owned by AURI and its staff. All AURI activities were and are consistent with charitable purposes under Sections 501(c)(3) and 509(a)(1), (2) or (3) of the Internal Revenue Code, and Agricultural Utilization Research Institute complied with all provisions and restrictions contained in the funding agreement, including, for example and without limitation, those provisions related to lobbying and political activity.

AURI's interest in this topic

AURI's mission centers on value-added agriculture — the transformation of raw agricultural commodities and coproducts into products of greater value after harvest. Consistent with the United States Department of Agriculture's (USDA) definition (USDA, n.d.), value-added agriculture involves changing the physical state or manner of production of a commodity, or physically segregating it, in a way that enhances its worth. Our work typically does not extend into production agriculture or agronomics; rather, we focus on what happens to farm outputs once they leave the field. While we do collaborate with agronomists and farmers engaged in production agriculture, this distinction is important when considering AURI's relationship to green ammonia and synthetic fertilizer production more broadly.

The manufacture of synthetic fertilizer, while indispensable to the agricultural supply chain, is fundamentally an industrial chemical process. The technologies, capital structures, and expertise involved in ammonia synthesis — whether conventional or green — differ substantially from those required to transform farm commodities into higher-value products. In that sense, fertilizer production falls outside the processing and utilization pathways in which AURI typically operates. Yet synthetic fertilizers remain among the most significant cost inputs in crop production, and the yields they sustain are foundational to the volume and quality of agricultural outputs available for value-added processing. The economics of fertilizer are therefore deeply embedded in every value opportunity we explore. Furthermore, when we consider broader issues of energy efficiency and decarbonization of value-added agricultural products, the contribution of synthetic fertilizers cannot be ignored.

This reality motivates our interest in green ammonia and other alternative fertilizers, but it also defines the boundaries of our involvement. Going forward, AURI does not anticipate advancing fertilizer production projects directly. Instead, we see our role as monitoring developments, advising stakeholders, and helping rural communities understand the trade-offs that emerging green ammonia and other alternative fertilizer technologies may entail. Our primary commitment remains fostering a vibrant rural economy and expanding the utilization of agricultural outputs — and to the extent that any shift in fertilizer markets affects those goals, positively or negatively, we intend to remain informed and engaged and committed to our role as trusted advisor to our stakeholders.

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Executive Summary

Synthetic ammonia is the chemical foundation of the modern nitrogen fertilizer system and, with it, the global food supply. It is also one of the most carbon-intensive industrial commodities, with conventional ("gray") production emitting on the order of 1.6–1.8 metric tons of carbon dioxide (CO_2) per metric ton of ammonia at best-available natural-gas configurations, and materially more for coal-based routes. Because more than 80 percent of ammonia is consumed as fertilizer, decarbonizing ammonia is one of the most direct levers available to reduce the greenhouse-gas (GHG) footprint of agriculture without sacrificing yield.

This report evaluates green ammonia — ammonia produced from electrolytic hydrogen and low-carbon electricity — as a partial substitute for conventional ammonia in Minnesota and the Upper Midwest. The conclusion is that green ammonia is technically mature enough to deploy but is not yet economically competitive on its own merits in commodity markets, and will not become so through market forces alone within the planning horizon relevant to project finance. Realizing its benefits will require deliberate, layered policy support; new contracting and risk-sharing structures; and a clear-eyed acknowledgment that green ammonia is one element of a broader transformation of the agricultural nutrient landscape — not a single-technology fix.

Minnesota's strategic vulnerability is structural, not cyclical

Minnesota has no primary ammonia synthesis capacity. Since the closure of the Magellan ammonia pipeline into Mankato in 2019, the state has relied almost entirely on rail and truck transport from out-of-state producers, distributed through a network constrained by limited storage, narrow seasonal application windows, and a shrinking pool of hazmat-qualified drivers. The result is a persistent inland "basis" — the spread between benchmark plant-gate prices and delivered prices into Minnesota — of several hundred dollars per ton, and recurrent in-season price and availability shocks.

The 2026 Strait of Hormuz closure has made the cost of that fragility visible at the farmgate. Within weeks of the late-February closure, U.S. anhydrous ammonia rose from roughly $828/ton (t) to about $1,120/t, and urea jumped roughly 50 percent. An April 2026 American Farm Bureau Federation survey reported that approximately 70 percent of farmers could not afford all of the fertilizer they needed for the season. This is not a one-off event; it is a reminder that a nitrogen system built around a handful of concentrated production regions and long maritime corridors will transmit geopolitical shocks directly into planting decisions. Resilience considerations therefore belong alongside cost analysis in any discussion of fertilizer supply.

The economics are difficult, and pretending otherwise serves no one

Across all colors of ammonia, hydrogen dominates production cost. For green ammonia, hydrogen cost is set primarily by electricity price and by electrolyzer capital cost and utilization. The updated AURI techno-economic model — grounded in current literature and recent project data — indicates that, for a representative 50,000 t/yr facility (about one-third of Minnesota's current anhydrous ammonia demand) at $20/MWh renewable electricity price and a roughly 30 percent electrolyzers capacity factor, unsubsidized levelized cost of hydrogen is on the order of $5.8/kg H_2 for alkaline electrolysis (higher for proton exchange membrane, PEM), translating to an unsubsidized levelized cost of ammonia of approximately $1,228/t. That is materially above Upper Midwest delivered prices in normal commodity years, and it is not close to parity through plausible movements in any single variable.

Critically, this 2026 update finds that the optimistic 2023 expectation of rapidly falling electrolyzer capital expenditure (CAPEX) has not materialized in the U.S. market. Federal policy uncertainty, restrictive 45V rulemaking, project cancellations, tariff exposure on imported (predominantly Chinese) alkaline equipment, and the hesitation of domestic manufacturers to scale have collectively held capital costs flat or modestly higher. The technical case for eventual cost reduction remains intact, but the business environment that would deliver it does not yet exist.

The implication is that in the near term, competing purely on commodity-market economics is not realistic. The competitive question is narrower and more defensible: whether a Minnesota facility can compete against the delivered cost of incumbent supply into local demand clusters, with the support of a credible policy and contracting framework. Even that narrower test is demanding.

Policy and incentives will be necessary, and production credits alone are not enough

In the modeled economics, the Section 45V clean-hydrogen production tax credit is decisive: under favorable eligibility, a \$3/kg H_2 credit can pull modeled ammonia cost into roughly the \$700/t range — plausibly competitive with delivered incumbent supply in Minnesota. But 45V is no longer a stable foundation for project finance. Eligibility under the four-pillar framework (incrementality, deliverability, temporal matching, attribute retirement) is narrow; the post-2025 policy environment, including the One Big Beautiful Bill changes, has compressed available runways and introduced material qualification risk; and the Heartland Hydrogen Hub has stalled even though it has not been formally canceled.

First-of-a-kind plants, therefore, need a layered package, not a single credit. Capital-side mechanisms (investment tax credits, grants, loan guarantees, accelerated depreciation, state-level investment credits, credit enhancements) reduce the upfront burden that the production-credit architecture does not address. Demand-side mechanisms (low-carbon procurement preferences, offtake guarantees, buyer-driven premiums tied to verified carbon-intensity reductions, environmental-attribute monetization) create the revenue stack that production credits alone cannot. Targeted instruments for the often-overlooked storage and working-capital burden — expedited permitting, public participation in strategic reserves, shared-use storage hubs, working-capital facilities — are essential as in-season ammonia storage is one of the most expensive, capital-intensive, and politically sensitive elements of any distributed concept. Policy is not a temporary subsidy here; it is the architecture that allows a high-capital, capital-cost-declining technology to reach the scale at which it can stand on its own.

Curtailed renewable power is an opportunity, but it is not free fuel

Midcontinent Independent System Operator (MISO)-corridor curtailment has grown substantially with Upper Midwest wind build-out and transmission congestion, and capturing low- or negative-price hours can meaningfully reduce blended electricity costs for a green ammonia plant. In practice, however, curtailment is location- and time-specific, and exploiting it is a coupled siting–sizing–storage problem: relying solely on curtailed power erodes utilization and inflates per-unit capital costs, while pairing it with power purchase agreement (PPA) volumes and flexible synthesis design changes the project profile considerably. A corridor- and site-specific feasibility study — integrating renewable procurement, interconnection strategy, hydrogen and ammonia storage sizing, and local offtake logistics — is a prerequisite to credible investment and is recommended as a follow-on to this work.

Stakeholders are conditionally willing, but the retail market has been moving away from direct ammonia use

AURI's supply-chain survey and stakeholder engagement across Minnesota confirms a consistent pattern: economics and availability are the primary adoption drivers, with safety and handling complexity as strong secondary concerns. A clear majority of retailers indicate a willingness to handle and sell green anhydrous ammonia if it is price-competitive, but that willingness drops sharply at any premium. Meanwhile, the retail nitrogen market has continued its long, structural shift toward urea — driven by ease of handling, lower regulatory burden, a shrinking anhydrous ammonia (AA) applicator workforce, and aging on-farm AA infrastructure — even though urea is typically slightly more expensive per unit of nitrogen and carries its own volatilization losses if mismanaged.

Realistically, the near-term agronomic objective for distributed green ammonia in the Upper Midwest is to stabilize current direct-application volumes rather than to engineer a wholesale return to anhydrous ammonia. Emerging options — aqua ammonia at lower pressure and concentration, smaller-scale on-farm or cooperative application systems integrated with precision-agriculture platforms — may lower the handling barrier within a local production-and-application radius, but none have yet emerged as a dominant design.

Green ammonia is one part of a new agricultural nutrient landscape

The most important framing in this report is that decarbonizing nitrogen and decoupling U.S. agriculture from long, fragile supply chains cannot be accomplished by substituting one molecule for another. It will require a portfolio of changes across the agricultural nutrient landscape, of which green ammonia is one component:

- **Improved nutrient-use efficiency and agronomy** — cover crops, no-till and strip-till, variable-rate and decision-support tools such as the Iowa Nitrogen Initiative's N-FACT, and the Minnesota Nutrient Reduction Strategy and Nitrogen Fertilizer Management Plan — can reduce synthetic nitrogen demand at the farm level by a meaningful margin while protecting water quality.
- **Recycled nutrients from manure and other organic streams** represent a substantial, underutilized resource. Published estimates suggest that better recovery and redistribution of manure nitrogen could supply up to one-third of Minnesota's nitrogen needs, provided that recovery technologies, transport logistics, and phosphorus-balance constraints are addressed. Food waste, biosolids, and other organic-waste streams add further potential where appropriate treatment and aggregation infrastructure exist.
- **Enhanced-efficiency fertilizers and microbial biologicals** remain promising but are not yet a consistent performing drop-in replacement at commodity scale; performance is variable across soils and seasons, and the evidence base required to support large-scale adoption is still being built.
- **Green urea from biogenic CO_2** — pairing green ammonia with concentrated, near-pure fermentation CO_2 from Midwest ethanol plants — is technically feasible and geographically logical, but is constrained by an incentive structure in which 45Q sequestration credits make the same CO_2 worth more underground than in a urea granule, plant-scale mismatches between fermentation CO_2 streams and economic urea

synthesis loops, and by Midwest CO_2 pipeline opposition. A small number of large, well-sited integrated facilities is plausible; but closing the multi-million-ton national urea import gap through this pathway is not, absent a fundamentally different policy framework.

- **Distributed green ammonia** contributes a domestic, electrolytic, import-free nitrogen source in its most concentrated form (82 percent N), which is most valuable where direct anhydrous-ammonia application is still operationally viable — the Upper Midwest — and where the renewable resource base can support electrolysis. It is best understood as a supply-security and rural-economic-development play with a real but secondary decarbonization benefit, rather than as a stand-alone decarbonization solution.

The United States has, over the past decade, reduced its reliance on ammonia imports while inadvertently increasing its reliance on urea imports — a system that is simultaneously cleaner and more fragile. A response requires investments along all of the above areas, not a single bet on any one of them.

Priority actions

The report's recommendations converge on five mutually reinforcing priorities, presented in order of how directly each addresses the binding constraints identified in this update:

- **Derisk first-of-a-kind projects with a layered policy package** that combines federal production credits where eligible with capital-side mechanisms (grants, loan guarantees, state investment credits, credit enhancements) and credible demand-side instruments (offtake structures, low-carbon procurement, verified carbon-intensity (CI) premiums). Production credits alone will not finance early plants.
- **Commission a corridor- and site-specific feasibility study** that integrates renewable procurement (including curtailment capture where feasible), interconnection strategy, hydrogen and ammonia storage sizing, and local offtake logistics for one or more Upper Midwest sites.

- **Build farm-level measurement, accounting, and certification tools** that quantify carbon-intensity reductions with the auditability, reproducibility, and low uncertainty that buyers, insurers, and financiers require to support premiums, contracts, and credit markets.
- **Create new local market structures** — demand-side procurement preferences; power-indexed fertilizer contracts paired with publicly backed risk backstops (insurance-style programs, capped contracts-for-difference, limited-duration price collars); cooperative ownership and participation models; expedited and standardized permitting pathways and shared-use storage hubs for code-compliant ammonia storage; and exploration of green urea at suitable ethanol-plant sites with lifecycle accounting that recognizes carbon is re-emitted after application.
- **Invest in the broader nutrient landscape in parallel** — manure and organic-waste nutrient recovery, enhanced-efficiency fertilizers, continued biologicals development, and farm-level nutrient management. These are not alternatives to green ammonia; they are complements, and several are likely to deliver lower-cost, faster greenhouse gas reductions than green ammonia alone.

Green ammonia is a technically credible, strategically important option for the Upper Midwest, and the structural case for it has grown stronger as the 2026 Strait of Hormuz closure has exposed how directly geopolitical fragility translates into farmgate economics. It is also expensive, capital-intensive, dependent on a policy environment that is currently unstable, and aimed at a retail nitrogen market that has been drifting away from direct ammonia application for operational reasons. Competing purely on market economics is not, and for the foreseeable future will not be, a realistic basis for deployment.

Sustained policy support, new contracting and risk-sharing structures, and locally rooted market arrangements are necessary conditions for a viable first wave of projects. They are not, by themselves, sufficient to decarbonize the fertilizer system or to insulate U.S. agriculture from concentrated, long-distance supply chains. That broader objective requires progress across the full agricultural nutrient landscape — nutrient-use efficiency, recycled nutrients, enhanced-efficiency products, biologicals, and selective downstream integration into green urea — in parallel with the build-out of distributed green ammonia. This report aims to provide an evidence base on which public and private stakeholders can make more informed decisions .

Differences from the 2023 report

An earlier version of this report was first issued in 2023. This 2026 release is a more extensive revision that considers a variety of changes that have happened since and attempts to address some shortcomings. Overall, the updated report offers a more complete and better contextualized narrative.

The update includes a revised economic analysis. While the fundamental premise does not change — the exploitation of the spread between local price and gate price of major producers to enable intrinsically disadvantaged new local manufacturers to compete, while providing the benefit of a reduced supply chain and retaining local value that would otherwise leave the region — a more challenging economic environment has been identified. To address this, AURI built a new, more sophisticated economic model of the process grounded in literature data.

The key challenge is capital cost. Green ammonia economics can be described mostly in terms of hydrogen cost and availability. In 2023, there was widespread optimism about the rapid decline in electrolyzer prices — the key capital cost component in green ammonia production. While the technical reasons for that optimism remain — there is no intrinsic technological reason why the electrolyzers could not follow the rapid cost-reduction curve seen for wind and solar power generation equipment, as demonstrated by current domestic Chinese costs that are considerably lower than U.S. costs — the business environment is not as favorable. A variety of factors negatively impact the outlook, leading to a reconsideration of initial capital costs remaining higher than expected. First, the uncertainty around federal policy — discussed in the report — and some restrictive rulemaking about its implementation, have led to many green hydrogen project cancellations or delays. This, in turn, has stunted manufacturers' interest in scaling up domestic production of electrolyzer devices for which the U.S. remains largely dependent on imports. At the time of this writing, import costs are affected by uncertain tariff policies, especially from China, which remains the dominant producer of lowest cost alkaline cell electrolyzers. Taking this situation into account and assessing real-life project costs in more detail, our projected capital cost estimates have not decreased and, in fact, have increased somewhat. Nonetheless, the opportunity for substantial cost reduction exists, but it is predicated on an initial industry build-up, which is currently difficult to predict. This observation, however, clearly indicates that lacking a federal support policy — or an insufficient one — other approaches, from state incentives and policies to new business models, monetization of environmental attributes, and more, are needed. While this report does not delve into those details, it provides a baseline to stimulate constructive engagement among public and private stakeholders.

One new area this report addresses is tapping into the large amount of curtailed renewable power currently available in relevant corridors of the Upper Midwest. Curtailed power is power that could be generated, but is not, because of a mismatch between supply and demand. While rare in conventional power generation schemes, this mismatch is common with solar and wind generation – collectively variable renewable energy (VRE) – where availability of power is dictated by wind and solar radiation intensity and not by users' demand. Curtailed power can be available at remarkably low prices, while, at the same time, there are grid benefits to treating a hydrogen plant as a variable load to ensure continuous matching of supply and demand. This argument is articulated while recognizing it requires follow-up work, since any more detailed analysis needs to be grounded on specific corridors and locations tied with grid topology and the location of generating assets.

General trends have not changed. Urea remains the preferred form of nitrogen at the retail level, and more detail is included on the differences between ammonia and urea while clarifying some misconceptions. Naturally, the merchant and retail ammonia prices have evolved since 2023. At that time, the fertilizer industry was still reeling from the effects of the 2022 fertilizer crisis[1],

[1] The 2022 crisis followed Russia's February 2022 invasion of Ukraine, which compounded an already tight market: global fertilizer prices had risen roughly 80% in 2021 and a further ~30% by early 2022 (World Bank, 2022). The war spiked European natural gas prices — the dominant feedstock and energy input for ammonia — forcing curtailment or shutdown of about 70% of European ammonia capacity by late 2022, while sanctions on Russian and Belarusian exports and Chinese export restrictions tightened supply further. The CRU fertilizer price index reached a record 390 in March 2022 (against its prior 2008 peak of 360); retail anhydrous ammonia exceeded roughly $1,600/t and urea $1,000/t (Jenkins, 2020), (Kee, Cardell, & Zereyesus, 2023). Because Russia is the world's largest fertilizer exporter

which had pushed global prices to unprecedented levels and led to shortages outside the U.S.. Prices subsequently stabilized through late 2025 at a new higher, but manageable, plateau than the historical pre-2022 one. At the time of writing, prices are being disrupted again by the 2026 Strait of Hormuz closure. The closure of the strait since February 28, 2026 has interrupted a corridor that under normal conditions carries roughly one third of seaborne fertilizer trade — including 30–35% of global urea exports and 20–30% of ammonia exports — alongside substantial shares of liquefied natural gas (LNG) and sulfur (UNCTAD, 2026) (Schnitkey, 2026), (Kpler, 2025) .

Nitrogen and phosphate fertilizer prices rose 20–40% in the weeks following the closure; U.S. anhydrous ammonia in particular moved from a Sept-2025-to-Feb-2026 average price of $828/t to roughly $1,120/t by mid-April 2026, while urea jumped about 50%, from the $400–$490/t range to around $700/t (CNBC, 2026), (The American Prospect, 2026). QatarEnergy halted downstream urea production alongside its LNG suspension, and China tightened fertilizer export controls to protect domestic supply (Foreign Policy, 2026), (The American Prospect, 2026)**.** The transmission to U.S. producers has been direct and is showing up at the farmgate rather than only in trade statistics: an April 2026 American Farm Bureau Federation survey of more than 5,700 farmers found that roughly 70% could not afford all the fertilizer they needed for the season — 78% in the South and close to half across the Midwest, with the regional gap largely explained by earlier purchasing in the latter region (Cordero, 2026), (American Farm Bureau Federation, 2026). Fertilizer has historically accounted for 33–45% of corn and wheat operating costs since 2020 according to USDA Economic Research Service data, which is why a price shock of this magnitude does not stay confined to the trade press but compresses farm margins and, in the most exposed cases, forces reductions in application during the planting window itself (USDA, n.d.)**.**

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and both Russia and Ukraine are critical suppliers to import-dependent regions, the affordability shock fell hardest outside the U.S., prompting emergency responses such as the African Development Bank's $1.5 billion Emergency Food Production Facility (Nti, 2022) (IFPRI, 2023)

The United Nations Food and Agricultural Organization (FAO) has warned that, because the crop calendar cannot be postponed, the supply disruption will be transmitted forward into the second half of 2026 and 2027 harvests, with up to 45 million additional people at risk of hunger, and has called for structural transformation to reduce dependence on concentrated supply routes and fossil-fuel-based inputs — including investments in sustainable agriculture, renewable energy, and innovative fertilizer solutions (FAO, 2026), (FAO, p. 2026) The episode is therefore not only a price event but a vindication of the structural case the present report makes: that the post-2022 plateau was never a steady state, that nitrogen supply with concentrated chokepoints and long supply chains translates more or less directly into U.S. farmgate economics during a spring planting window, and that resilience considerations belong on the same page as plant-gate cost analysis. U.S. natural gas, the main domestic source of hydrogen for conventional ammonia, remains inexpensive and has been largely insulated from the disruption — if anything, the crisis has strengthened incumbents' domestic margins. The spread between their plant-gate cost and the Minnesota local retail price, therefore, continues to provide a wedge to work on, but one which needs to be exploited carefully and does not completely remove the need for incentives. In this first phase of industry build-out, we argue these would be better aimed at capital investment and project development than production per se.

Ammonia today

More than 80 percent of global ammonia production is used for fertilizer, either directly or as a feedstock for the synthesis of other fertilizers such as urea, ammonium phosphates, and others (see Figure 1). Ammonia synthesis is among the largest carbon dioxide-emitting chemical processes – accounting for 1.8 percent of global greenhouse gas (GHG) emissions (The Royal Society, 2020) (see Figure 2). Nitrogen-based inputs such as anhydrous ammonia (AA), urea, and other ammonia derivatives are widely used to maximize the yield of crops grown for food, fuels, and livestock feed. Currently, it would be impossible to maintain the world's food output without the supply of synthetic fertilizers and ammonia-based fertilizers in particular (Dawson & Hilton, 2011), (Erisman, Sutton, Galloway, Klimont, & Winiwarter, 2008). The synthetic ammonia process allows the fixing of virtually unlimited atmospheric nitrogen into biologically active ammonium and is responsible for more than doubling the amount of biologically available nitrogen (Smil, 2004).

On the other hand, the need for carbon and energy-intensive synthetic nitrogen fertilizers is a considerable obstacle to decarbonizing agricultural supply chains. Feedstock and agronomy practices can account for up to 13% of the carbon intensity of biofuel production, with synthetic fertilizer inputs being one of the largest inputs. (Algren, Landis, & Costello, 2021), (Scully, Norris, Alarcon Falconi, & MacIntosh, 2021). Therefore, it is important to consider the environmental and economic impacts of producing, transporting, storing, and utilizing these fertilizers as demand grows for low-carbon intensity products.

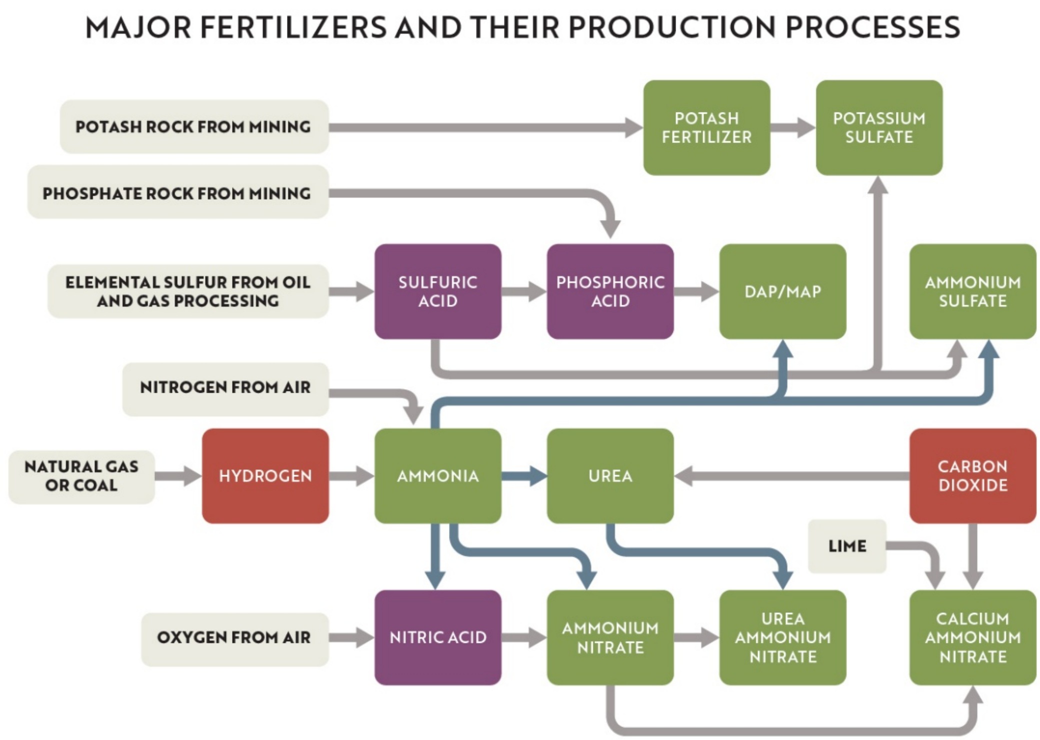

Figure 1: Major Fertilizers and their Production Processes.

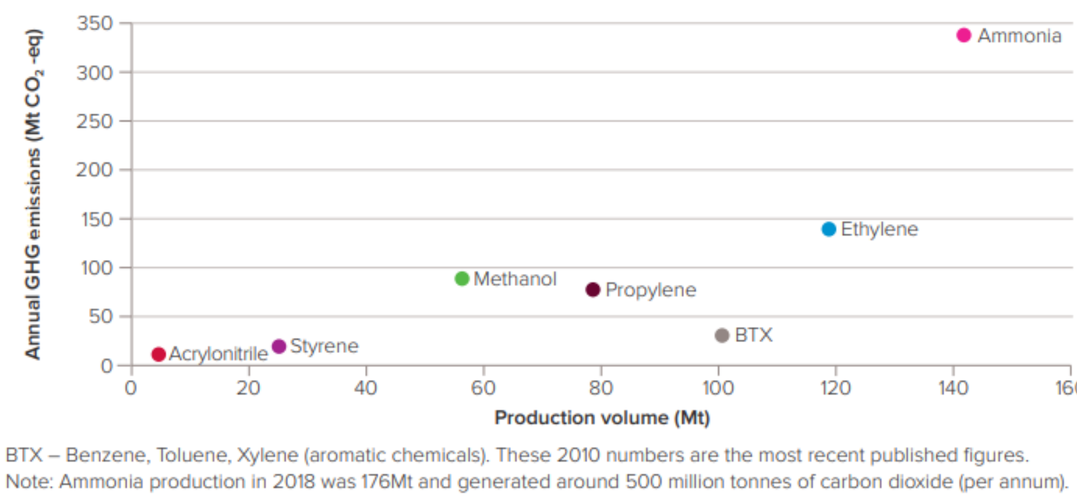

Figure 2: Greenhouse Gas Emissions for Selected High Production Volume Chemicals for 2010 (The Royal Society, 2020).

The predominant source of industrial ammonia is the Haber-Bosch process (Figure 6), which synthesizes ammonia by reacting hydrogen and nitrogen at high temperatures and pressure over a metallic catalyst. This process, developed in Germany during the early part of the 20th century

(Smil, 2004), is one of the most consequential chemical syntheses in the history of humankind and is seen as essential to enabling the mid-century green revolution (Erisman, Sutton, Galloway, Klimont, & Winiwarter, 2008). There are few innovations that have transformed the world as much as synthetic nitrogen; estimates suggest that one in two people are alive today because global food production, enabled by these fertilizers, could expand beyond the relatively limited amount of naturally occurring nutrients available for crops (Ritchie, 2021).

Today, many independent vendors offer ammonia synthesis processes. While these modern processes are considerably more efficient than the original 1904 process, they are all conceptually based on the same chemistry.

$$N_2 + 3H_2 \rightarrow 2NH_3$$

Nitrogen is obtained from the atmosphere via an air separation unit (ASU), while hydrogen is typically obtained from the steam methane reforming of natural gas (SMR). SMR is efficient but carbon- intensive. Originally, coal gasification was the primary source of hydrogen, which is even more carbon-intensive than SMR. The use of coal for hydrogen production was largely abandoned in the Western world[2] (The Royal Society, 2020) but remains common in China.

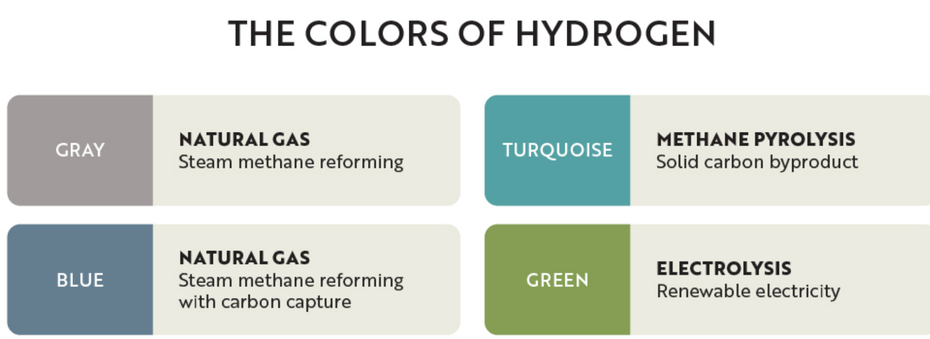

Figure 3: Color Classification of Hydrogen (and Ammonia); ammonia has the same color taxonomy of hydrogen since ammonia synthesis comes from hydrogen and requires no additional energy inputs. The

[2] A noticeable exception is the Dakota Gasification Company in Beulah, ND (www.dakotagas.com) where CO2 is sequestered for underground storage. Their stated ammonia production is 355,000 tons per year. At the same facility the company also produces urea and ammonium sulfate.

illustration shows only the most relevant colors Adapted from (Belfer Center, 2024).

Hydrogen is classified by a color taxonomy that reflects its production pathway and associated carbon emissions rather than any physical property of the gas itself (**Error! Reference source not found.**). Gray hydrogen, which accounts for the vast majority of current production, is derived from natural gas via SMR and releases significant CO_2. Blue hydrogen uses the same process but pairs it with carbon capture and storage to reduce emissions. In addition, black and brown hydrogen – not indicated in Figure 3) are produced from bituminous and lignite coal, respectively, through gasification — the most carbon-intensive method. Green hydrogen, produced by electrolysis of water powered by renewable energy, generates no direct carbon emissions and represents the only truly zero-carbon production pathway[3].

Ammonia largely inherits the environmental properties and carbon intensity of the hydrogen used to produce it. Thus, the same color taxonomy can be used and ammonia produced with hydrogen obtained from natural gas (NG) is referred to as conventional or "gray." Green ammonia differs in the source of hydrogen and how it is generated. In green ammonia production, hydrogen is produced by electrolysis of water powered by renewable energy sources such as wind and solar. Electrolysis itself has no direct carbon emissions. If the power source is renewable, indirect emissions—other than those associated with the manufacturing of the electrolysis cells—are also absent. The ammonia synthesis step is the same in both processes (Kub, 2021) (**Error! Reference source not found.**) Other than the source of hydrogen, green a mmonia is chemically and functionally indistinguishable from conventional ammonia. Thus,

[3] Additional designations include pink and purple (nuclear-powered electrolysis using respectively conventional or high temperature solid oxide electrolyzers), turquoise (methane pyrolysis yielding solid carbon rather than CO_2), yellow (solar-powered electrolysis), and white (naturally occurring geological hydrogen). While the taxonomy continues to expand, the core distinction remains the carbon intensity of the production process.

green ammonia is a "drop-in" replacement for gray ammonia, enabling seamless integration into existing supply chains and requiring no adaptation or change by the end user.

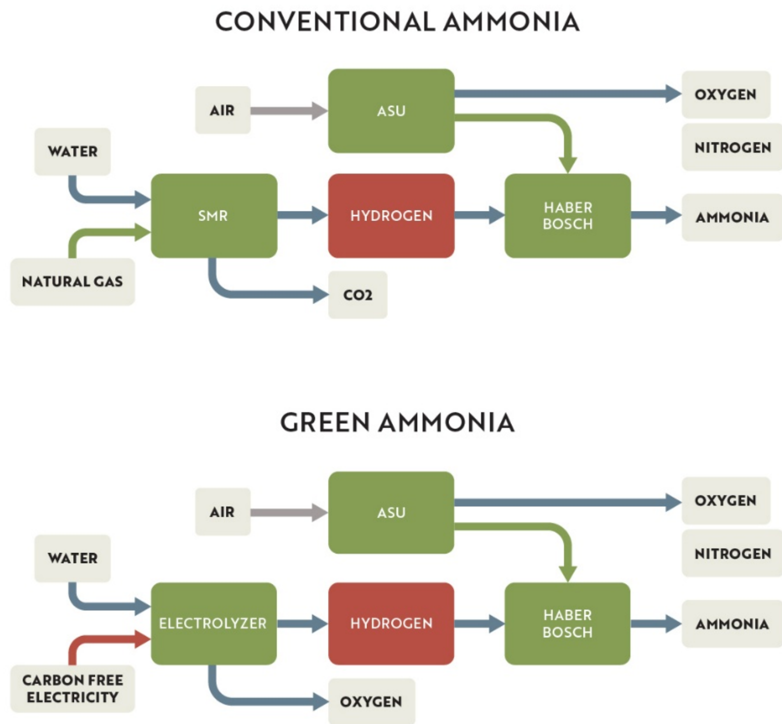

Figure 4: Conventional versus Green Ammonia electrolysis; SMR = Steam methane reforming; ASU = Air Separation Unit; CO2 produced is approximately 1.6 tons for a ton of ammonia.

A cradle-to-gate LCA of distributed hydrogen production (global warming potential [GWP], 100-year basis) was conducted by scientists at The Royal Society of Chemistry in 2024 (Figure 5), who found that green hydrogen (green ammonia) provides emissions reductions of 80-95% compared to grey hydrogen (grey ammonia) (Patel, Havukainen, Horttanainen, Soukka, & Tuomaala, 2024).

> *"Results for the production of green hydrogen demonstrate that connecting the electricity grid solely to wind energy results in a total emission of 0.6 kg CO_2 eq. per kg H_2. Conversely, connecting the electricity grid only to solar energy results in a higher total emission of 2.5 kg CO_2 eq. per kg H_2. When the electricity grid is connected to both solar and wind energy in a 50*

: 50 ratio, most emissions come from solar energy, which emits 1.2 kg CO_2 eq. per kg H_2. Emissions from wind energy are lower, of 0.3 kg CO_2 eq. per kg H_2, and only a small amount comes from manufacturing the electrolyzer. The total emission for this is 1.5 kg CO_2 eq. per kg H_2, as illustrated in Figure 5. (Patel, Havukainen, Horttanainen, Soukka, & Tuomaala, 2024)."

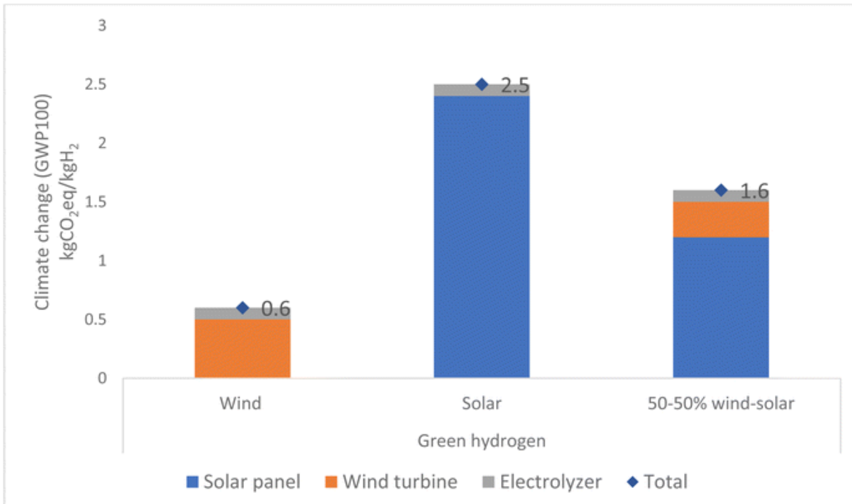

Figure 5: Total distributed LCA results of green hydrogen production (GWP100 years). (Patel, Havukainen, Horttanainen, Soukka, & Tuomaala, 2024).

On a direct, plant-gate basis (Scope 1 CO_2 from on-site process and fuel), conventional fossil-based (gray) ammonia produced via the Haber-Bosch process with hydrogen from natural-gas steam methane reforming (SMR) typically emits about 1.8 metric tons of CO_2 per metric ton of ammonia (t CO_2/t NH_3) for best-available technology, while natural-gas autothermal reforming (ATR) is about 1.6 t CO_2/t NH_3. Coal-gasification-based ammonia is materially higher at about 3.2 t CO_2/t NH_3 for best-available technology, and values across existing fleets are commonly reported in the ~3.2–4.5 t CO_2/t NH_3 range depending on plant configuration and performance. (Figure 6). Emissions are therefore considerably higher in jurisdictions where coal-based hydrogen dominates. In China, coal accounted for about 85% of domestic ammonia production in 2019, which pushes average production emissions well above natural-gas-based routes. In terms of end use, around 70% of global ammonia is used to make mineral fertilizers, with the remaining roughly 30% used as an industrial feedstock for products including plastics, explosives, and synthetic fibers[4].

Green ammonia is synthesized using hydrogen from water electrolysis powered by low-carbon electricity (plus nitrogen from air separation). The molecule contains no carbon, but calling it "carbon-free" is misleading: it is only low-carbon on a life-cycle basis if the electricity (and upstream supply chains) is low-carbon. When those conditions are met, green ammonia can support industrial decarbonization as a:

- fuel or energy carrier for certain industrial heat, shipping, and power-generation applications
- hydrogen carrier that can be transported and stored in bulk more easily than gaseous hydrogen, then cracked back to hydrogen where needed

These uses are not plug-and-play: they require tight control of nitrogen oxides (NOx) and ammonia slip, and cracking adds cost and efficiency penalties.

Using renewable power to generate hydrogen, which is then converted into ammonia for cracking into hydrogen or used directly for power generation, may appear counterintuitive but is based on plausible energy economics. Transporting electricity over long distances can be expensive primarily because new transmission is capital-intensive and slow to permit and build, and its delivered cost increases sharply if the line is not highly utilized. Several comparative assessments (DeSantis, James, Houchins, Saur, & Lyubovsky, 2021) find that, for large

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[4] A concrete example of ammonia's role as a chemical precursor is acrylonitrile. Most acrylonitrile is produced via catalytic ammoxidation of propylene (the SOHIO process), which uses ammonia and air as reactants. Acrylonitrile is a key intermediate for products including ABS plastics, nitrile rubbers, acrylic fibers, and polyacrylonitrile (PAN) fibers. PAN is the dominant precursor for carbon fiber, representing about 90% of global carbon-fiber production. Carbon-fiber-reinforced polymers provide high specific strength and stiffness and are now widely used in aerospace lightweighting; for example, modern wide-body aircraft such as the Boeing 787 and Airbus A350 families rely heavily on composite structures (on the order of ~50% by weight). While ammonia demand from these non-fertilizer value chains is real, it remains small relative to fertilizer use overall. Chemical feedstock demand is unlikely to be a volume driver for ammonia, but it could support localized, premium offtake for certified low-carbon ammonia where buyers value Scope 3 reductions and logistics/resilience benefits enough to pay for it.

throughputs and long distances, transporting energy as molecules in pipelines can be materially cheaper per unit of delivered energy than building new long-distance transmission, although the result depends on distance, capacity factor, and the specific infrastructure assumed. Pipelines carrying gases also provide limited short-term buffering via linepack[5], which can help manage intra-day variability. For hydrogen specifically, dedicated pipelines may require higher-cost design choices due to high-pressure service and hydrogen embrittlement considerations. By contrast, liquid ammonia does not pose a hydrogen embrittlement risk and can often use conventional pipeline materials and operating practices, which is one reason ammonia is frequently discussed as a long-distance hydrogen carrier (Figure 6). This has driven interest in ammonia as an energy carrier for converting low-cost renewable electricity in remote, high-resource regions into a transportable product that can reach distant demand centers. While these applications are out of scope for this study, they are noted because they could plausibly help accelerate green-ammonia deployment and infrastructure build-out and could indirectly benefit fertilizer markets through scale, learning, and increased availability of certified low-carbon ammonia.

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[5] Linepack is the total quantity of gas held within a pipeline system at any given time, conventionally reported in millions of cubic meters (or, in North American practice, billions of cubic feet; energy-equivalent units such as GWh are also used) (National Gas Transmission, 2023). Because natural gas is compressible, the volume of gas held in a pipeline can be varied by adjusting the operating pressure between its minimum operational level and its maximum allowable operating pressure — providing short-term flexibility for buffering intraday supply-and-demand mismatches, though not a substitute for dedicated working-gas storage. This would apply only to a hydrogen pipeline, not to an ammonia pipeline, ammonia being transported as a liquid, thus incompressible at pipeline conditions.

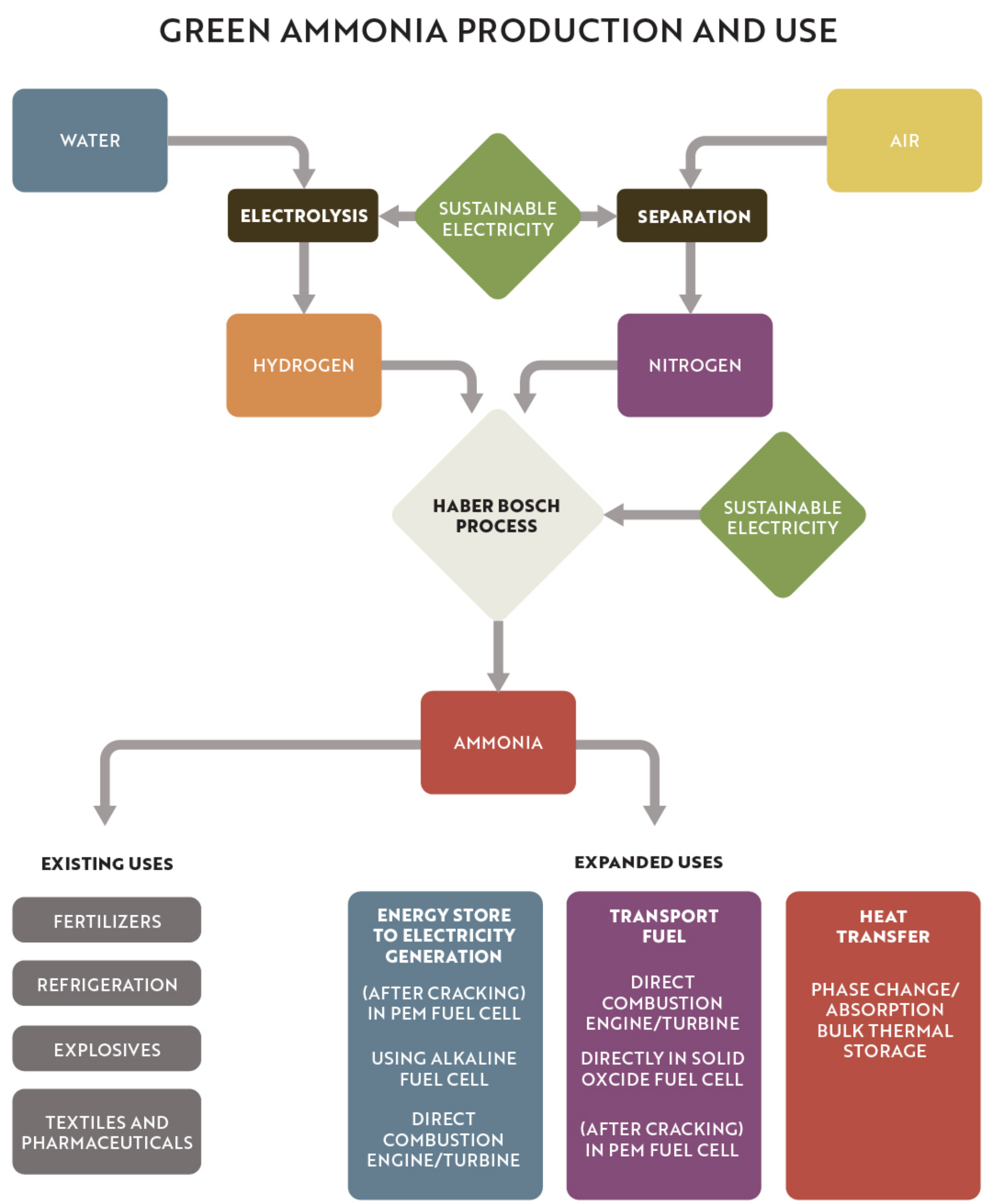

Figure 6: Green Ammonia Production and Uses. Adapted from (The Royal Society, 2020).

The U.S. is a large producer of ammonia but remains an importer although the reliance on imports has decreased considerably (U.S. Geological Survey, 2026) and (U.S. Geological Survey, 2024). Inexpensive natural gas has made domestic production increasingly competitive as indicated in an uptick in exports (Figure 7). Additionally, Table 1 illustrates ammonia production facilities in the United States as of 2021. Largely, this remains the current status of the industry, although there were considerable expansions announced in the last several years (APPENDIX 1: Proposed Expansions in Ammonia Production Since 2022 And Current Status of the Industry).

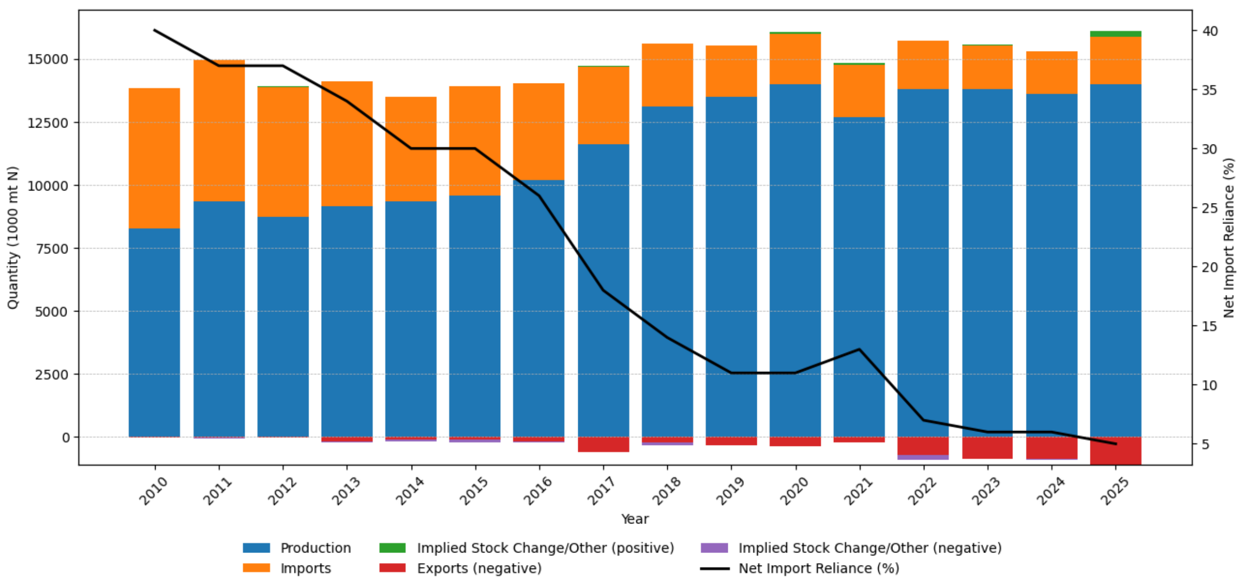

Figure 7: The U.S. Ammonia Market (U.S. Geological Survey, 2026).

Table 1: Domestic U.S. Ammonia Production Site with Nominal Capacity.

Company	Capacity (kta)	Capacity (tpd)	State	Location	Region
CF Industries Inc.	3,930	11,229	LA	Donaldsonvill e	S
CF Industries Inc.	1,120	3,200	IA	Port Neal	MW
CF Industries Inc.	1,100	3,143	OK	Verdigris	S
Koch Fertilizer Company	930	2,657	OK	Enid	S
Dyno Nobel Inc.	800	2,286	LA	Waggaman	S
Iowa Fertilizer Co.	770	2,200	IA	Wever	MW
Nutrien	765	2,186	GA	Augusta	SE
Yara/BASF JV	750	2,143	TX	Freeport	S
Nutrien Lima Nitrogen	725	2,071	OH	Lima	MW
AdvanSix	540	1,543	VA	Hopewell	E
Nutrien	535	1,529	LA	Geismar	S
CF Industries Inc.	517	1,477	MS	Yazoo City	S
Mosaic Company	510	1,457	LA	Faustina	S
LSB Industries - Eldorado Chemical Co.	490	1,400	AR	El Dorado	S
Nutrien	490	1,400	TX	Borger	S
CF Industries Inc.	435	1,243	OK	Woodward	S
Coffeyville Resources	375	1,071	KS	Coffeyville	MW
East Dubuque Nitrogen Fertilizers	360	1,029	IL	East Dubuque	MW
Dakota Gasification Company	355	1,014	ND	Beulah	MW
Koch Industries Inc.	350	1,000	IA	Fort Dodge	MW
OCI Beaumont LLC.	332	949	TX	Beaumont	S
Koch Ag. & Energy Solutions	280	800	KS	Dodge City	MW
Nutrien	280	800	AK	Kenai	W
Koch Fertilizer Beatrice	265	757	NE	Beatrice	MW
LSB Industries - Pryor Chemical Co.	240	686	OK	Pryor	S
J.R. Simplot Co.	185	529	WY	Rock Springs	W
LSB Industries - Cherokee Nitrogen	185	529	AL	Cherokee	SE
Nutrien	180	514	WA	Kennewick	W
Dyno Nobel Inc.	178	509	WY	Cheyenne	W
Dyno Nobel Inc.	100	286	OR	St. Helens	W
U.S. Nitrogen LLC.	62	177	TN	Greenville	SE
NE Nitro Geneva, LLC	33	94	NE	Geneva	MW
Green Valley Chemical	32	91	IA	Creston	MW
Shoreline Chemical	30	86	GA	Gordon	SE
Chevron Chem. Co.	18	51	CA	El Segundo	W
Totals					
Total (kta)	18,247	52,136			
Average (tpd)		1,490			

The Ammonia Market

Anhydrous ammonia (AA) prices typically fluctuate based on natural gas price, nitrogen fertilizer demand, and – to an extent yet to be fully assessed – the expected price of corn. - Fertilizer is traded on a global market. Consequently, geopolitical events – such as the conflict between Russia and Ukraine in 2022 (International Agricultural Trade Report, 2022) – and weather conditions in places like the Lower Mississippi Delta, where much of the U.S. supply of nitrogen is produced, also impact AA price. Thus, stable natural gas prices are not necessarily indicative of stable AA prices, as indicated by Figure 8 from a 2022 report from the U.S. Energy Information Administration.

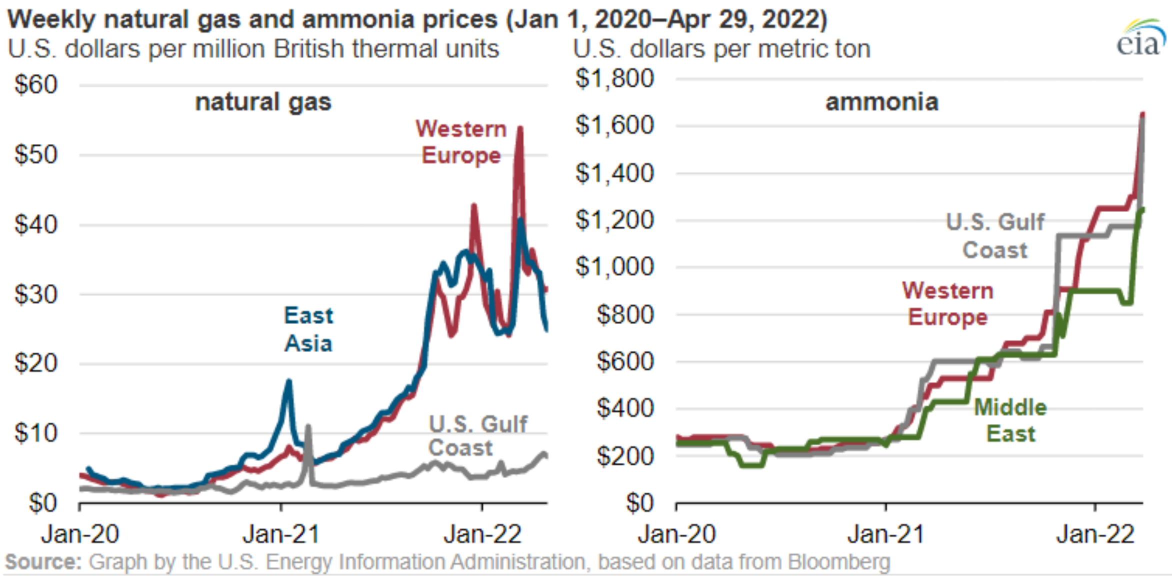

Figure 8: Weekly natural gas and ammonia prices (Jan 1, 2020 - April 29, 2022) (U.S. Energy Information Administration, 2022).

In mid-2025, the Department of Agricultural and Consumer Economics at the University of Illinois reported the local AA price in Illinois of $786/ton, which reflects a new, relatively stable, yet higher than historical standard level since the 2021-2023 period, characterized by higher prices and high volatility (Figure 9). Prices are forecast to remain in the $750 to $800/ton during 2026 (Paulson, Schnitkey, Monaco, & Zulauf, 2025).

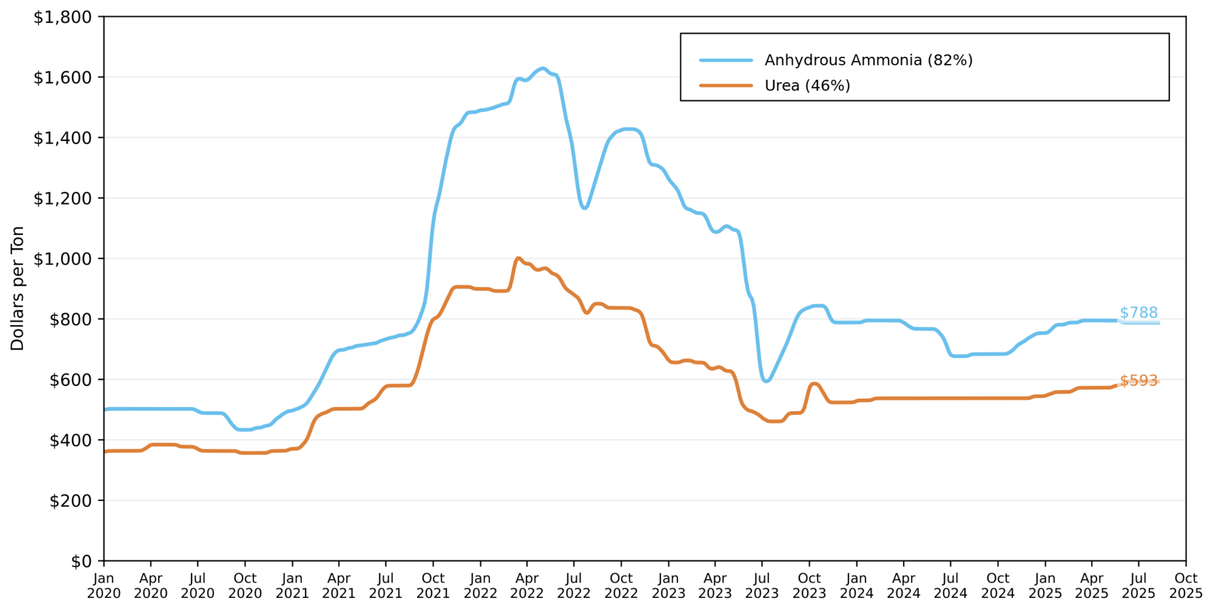

Figure 9: Illinois nitrogen prices 2020-2025, adapted from (Paulson, Schnitkey, Monaco, & Zulauf, 2025). Data from USDA, University of Illinois Urbana-Champaign, and FarmDoc Daily.[6]

Demand for nitrogen remains high and is expected to remain robust if farmers keep pushing for higher agricultural productivity (Figure 10, Figure 11). New markets may be established for ammonia (International Energy Agency, 2021), (International Renewable Energy Agency, 2022), even as the form in which end users prefer to apply it is changing (Figure 12). These figures demonstrate a shift in demand from AA to urea. Because AA has the highest concentration of all forms of nitrogen, it is also the most cost-effective and efficient, and can be applied in the fall because nutrient losses are minimal over the winter compared to other forms of nitrogen. However, while AA was historically the most commonly applied source of nitrogen, it is more hazardous than urea if not handled properly when transporting (U.S. Government Accountability Office, 1998), storing and applying (Minnesota Department of Agriculture, n.d.).

[6] We use the Illinois price as a proxy for Midwest prices because Illinois maintains detailed retail price statistics. The Minnesota Department of Agriculture collects detailed sales data but does not track retail prices. Anecdotally, Minnesota prices — particularly in the northern part of the state — tend to be higher than Illinois prices and at times substantially so. Using Illinois data therefore provides a conservative basis for our analysis, and future studies should prioritize collecting better information on local Minnesota retail prices.

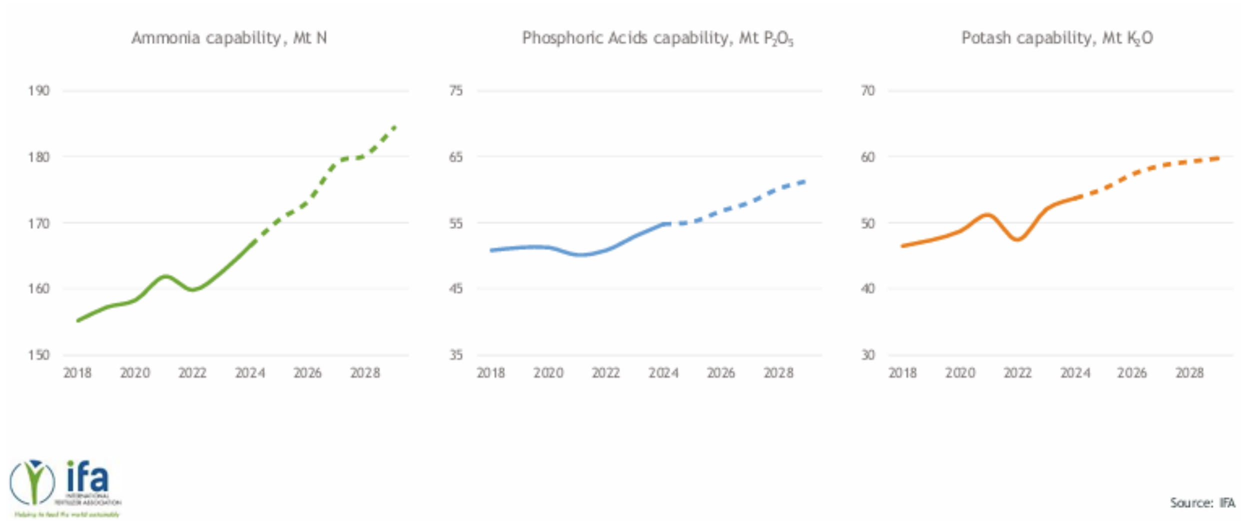

Figure 10: International Fertilizer Association Mid-term Projections for Fertilizer Demand from 2025-2029 (International Fertilizer Association, 2025).

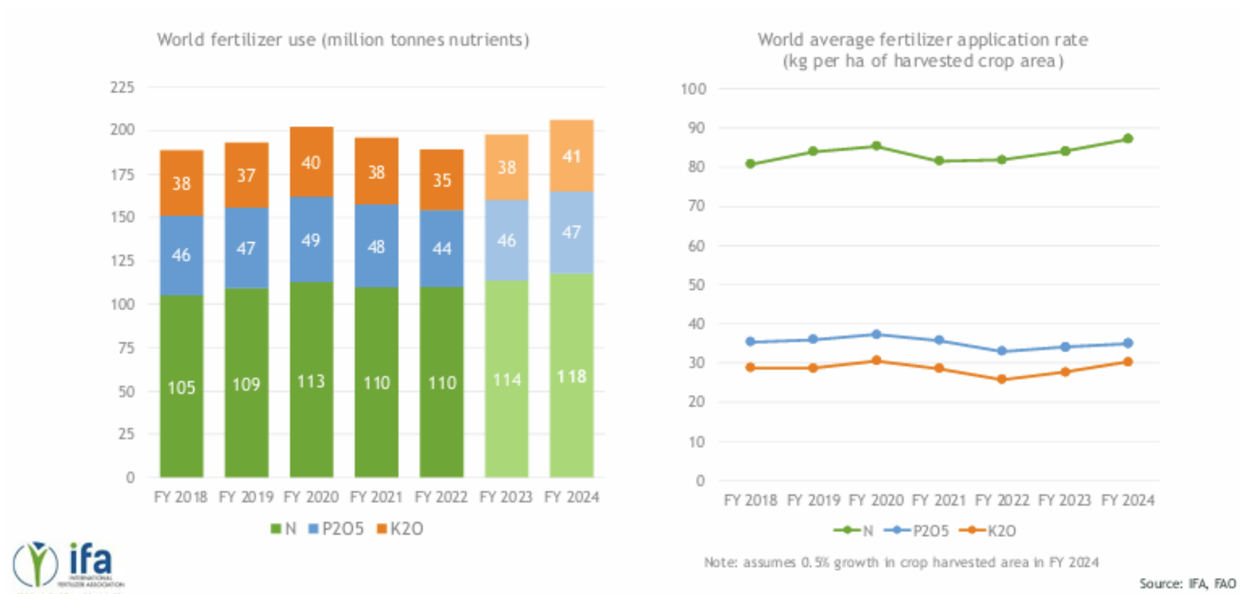

Figure 11: International Fertilizer Association Mid-term Projections for Fertilizer Consumption from 2025-2029 (International Fertilizer Association, 2025).

The shift toward urea is further facilitated by the preferences of dealers and distributors who appreciate urea's simplified, cheaper, less regulated, and more flexible handling and storage. It should also be noted that the shift to urea and the current consumption of anhydrous ammonia in the state appears to have stabilized at around 150,000 tons per year (Figure 12) (MDA, 2024). This section was framed before the 2026 Strait of Hormuz closure added a strategic dimension that compounds, rather than competes with, the convenience-and-cost dynamics described above. The same period in which retail demand has shifted toward urea is also the period in which the U.S. has materially reduced its ammonia import reliance — from roughly 40% of apparent consumption in 2010 to about 6% in 2024 (USGS, 2025) — while urea has remained structurally import-dependent, with imports covering roughly 40–50% of consumption and the Persian Gulf region (notably Qatar and Saudi Arabia, together approximately 16% of U.S. urea imports in 2024) supplying a large share of those volumes (USGS, 2025; see also Appendix 6: The Ammonia–Urea Nexus). One-third of seaborne urea trade transits the Strait of Hormuz and the migration of farm-gate demand from AA toward urea has effectively moved the nation's nitrogen-supply vulnerability one step downstream, where it is less visible but no less real.

The closure of the Strait since late February 2026 has stress-tested that dependence in real time: free on board (FOB) price for granular urea has moved from the $400–490/t pre-crisis range to approximately $700/t, with U.S. anhydrous ammonia repricing in parallel (see 'Differences from the 2023 release' above for the full price evolution and supporting sources; Farmdoc Daily, 2026; FAO, 2026). The episode reinforces, rather than contradicts, the structural case made by this report for distributed, domestically produced green ammonia — and, where biogenic CO_2 is available (as at ethanol plants), for locally synthesized green urea — as a way to keep more of the nitrogen value chain inside the region while reducing exposure to maritime chokepoints (see also Appendix 6).

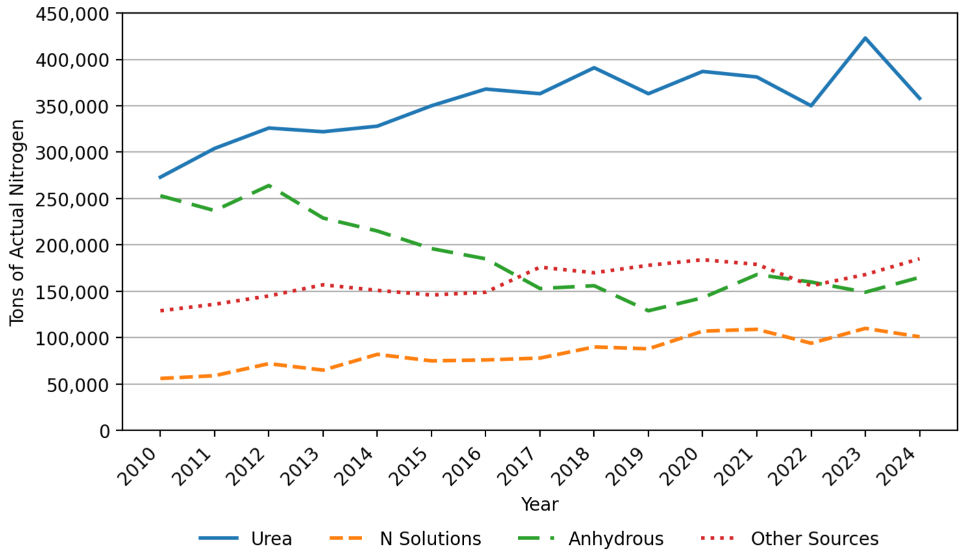

Figure 12: Minnesota nitrogen sales over time. (Minnesota Department of Agriculture, 2025).

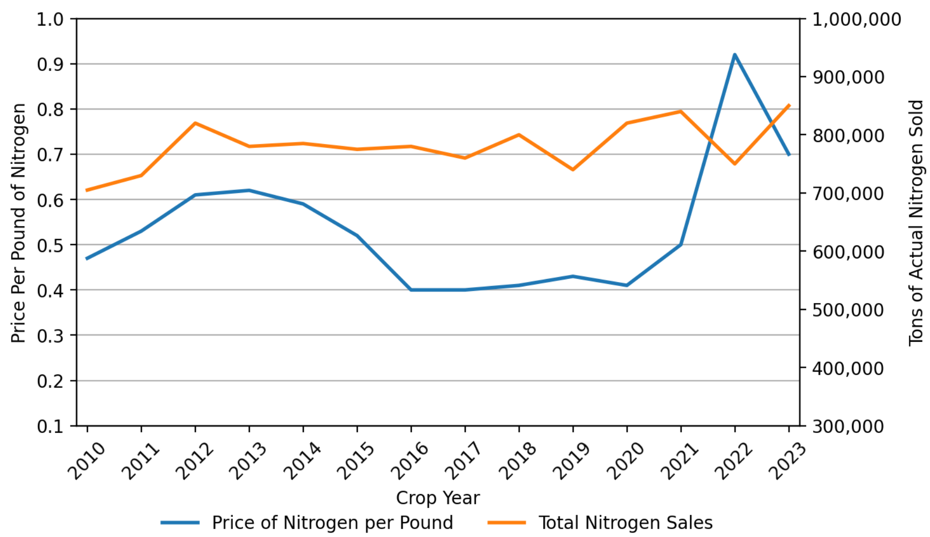

Figure 13: Minnesota price of actual nitrogen per pound and total tons of actual nitrogen sold from 2010 to 2023. Sources, Minnesota Department of Agriculture and DTN Progressive Farmer (Minnesota Department of Agriculture, 2025).

While the U.S. has substantially expanded domestic ammonia production capacity in the last several years —reducing import reliance from approximately 40% of apparent consumption in 2010 to roughly 6% in 2024 —domestic prices remain tied to global benchmarks because ammonia is a globally traded commodity. This means that even as import volumes decline, Minnesota farmers remain exposed to international price volatility. Furthermore, because

Minnesota has no primary ammonia synthesis capacity—the state hosts blending and formulation operations but no Haber-Bosch production plants—all ammonia must be transported into the state from production regions concentrated in the Gulf Coast and Southern Plains. An ammonia pipeline does not extend into Minnesota, limiting inbound supply to rail, barge, and truck (U.S. General Accounting Office, 1998) (Figure 21). While bulk ammonia may reach regional distribution points by rail or river barge, final delivery to in-state retailers and farms depends heavily on truck transport — the most expensive mode for moving bulk commodities on a per-ton-mile basis. This cost burden is compounded by a persistent shortage of drivers holding the hazmat endorsements required for AA transport, which can create seasonal bottlenecks and price spikes during peak application season.

Ammonia production is among the most carbon-intensive industrial processes, with virtually all global output relying on fossil fuel feedstocks. According to the IEA (International Energy Agency, 2021) , just over 70% of ammonia is produced via natural gas-based SMR, with most of the remainder—approximately 26%—derived from coal gasification (IEAGHG, 2023). Because natural gas serves as both the primary hydrogen feedstock and the dominant energy source for the Haber-Bosch process, it typically accounts for 70–90% of the cash cost of ammonia production (CF Industries, 2022) (American Gas Association, 2023) making ammonia prices acutely sensitive to natural gas market fluctuations. While clean ammonia technologies—including blue ammonia (with carbon capture) and green ammonia (electrolysis-based)—are advancing, low-emission production currently represents less than 1% of global supply (International Energy Agency, 2025) and considerable cost premiums over conventional production make widespread adoption in the fertilizer sector challenging in the near term without incentives or policy interventions. For the foreseeable future, the delivered cost of nitrogen fertilizer to Minnesota farms will remain fundamentally coupled with natural gas pricing.

Current and planned U.S. ammonia capacity expansions have increased domestic capacity and are reducing the reliance on imports, but the majority of these new and retrofitted plants will rely on natural gas. Some will implement carbon capture and storage (CCS) to reduce their carbon intensity by capturing a portion of the direct CO_2 emissions from the process. The captured CO_2 would be injected into subtrranean geological formations for permanent storage, rather than being released into the atmosphere. CCS will decrease the carbon intensity of the industry, but the transition to a low-carbon feedstock, such as electrolytic hydrogen obtained from renewable power, remains limited to a few small-scale facilities such as the plant operated by TalusAg in Boone, Iowa (APPENDIX 4: TalusAg Green Ammonia Demonstration Plant — Boone, Iowa).

Of note:

- CF Industries is producing eight million tons per year at “the world’s largest and most flexible ammonia production facility” that operates continuously in Donaldsville, LA (CF Industries, 2026).
- Greenfield Nitrogen LLC. announced an 83,000-ton-per-year plant in Gardner, IA and plans to unroll farmer participation in early 2026 (Greenfield Nitrogen LLC., 2026).
- Monolith Materials invested in an expansion of their flagship facility in Hallam, NE, “Olive Creek 2” (Monolith Materials, 2026) and construction is expected to be complete in 2027, making it among one of the largest commercial-scale hydrogen plants in the world. Monolith has five near-term projects of similar size in its development pipeline and “up to 40 additional projects under consideration” (Monolith Materials, 2023).

CF Industries and Greenfield will use electrolytic hydrogen (H_2), while Monolith will use H_2 from the pyrolysis of methane. Methane pyrolysis produces hydrogen by cracking the methane molecule into hydrogen and solid carbon. The latter is recovered and sold as carbon black in the plastic and rubber market. Methane pyrolysis, while still dependent on methane, does not produce CO_2 and does not need CCS. As stated by Iowa State University’s Center for Agriculture and Rural Development, “energy drives the supply of fertilizer production, and food drives the demand for fertilizer use, and the two biggest components of inflation right now are energy and food” (Iowa State University Center for Agricultural and Rural Development, 2022). AA consumption and pricing are closely tied to crop markets, especially corn (U.S. Energy Information Administration, 2026) (Figure 15), which does not fix its own nitrogen and requires fertilizer applications as a key input to meet yield potential. As crop prices have nearly doubled in recent years, fertilizer prices have increased two to four times since September 2020 (Iowa State University Center for Agricultural and Rural Development, 2022).

Ammonia Economics and Implications for Minnesota

The variable cost of conventional ("gray") ammonia is dominated by natural gas, which serves as both the hydrogen feedstock and a primary process fuel; the contribution of natural gas cost to ammonia production varies between 70% and 90% of manufacturing costs (Ghavam, Vahdati, Grant Wilson, & Styring, 2021). Because hydrogen feedstock is required at the stoichiometric ratio of approximately 0.176 kg H_2 per kg NH_3 (3 mol H_2 per 2 mol NH_3), the variable hydrogen cost component of ammonia levelized cost of production (LCP) scales linearly with LCOH. In their economic assessment of low-carbon hydrogen carriers, KBR – a major ammonia technology provider - applies this scaling explicitly (KBR, 2022). Hydrogen production, which conventionally uses natural gas both as feedstock and as fuel, also represents the largest amount in ammonia synthesis (Mingolla & Rosa, 2025). This dependency on natural gas[7] has historically concentrated ammonia production in regions with low-cost gas.

In the U.S., an extended period of relatively low domestic natural gas prices justified plant upgrades and capacity additions, contributing to a large reduction in U.S. net import reliance—from roughly 40% in 2010 to an estimated ~5% in 2025, based on United States Geological Survey (USGS) net import reliance as a share of apparent consumption (reference). This link between production economics and natural gas inputs led to a long period of low, stable ammonia prices. As a result of low and stable natural gas prices, ammonia's production cash cost before 2021 was estimated to be between \$160 and \$200 per ton, which ensured good margins for producers with a sales price (U.S. Gulf basis) of around \$300 per ton (see Figure 7).

This long, stable period was already ending, with prices showing a slow but distinct upward trend before the 2022 crisis (see footnote 1) . While ammonia prices and natural gas prices are linked,

[7] Traditionally, this would have also applied to coal; however, reliance on coal as a hydrogen—and thus ammonia—feedstock in the Western world has largely receded. With very few exceptions, coal-to-ammonia plants are now mostly concentrated in China, where they account for approximately a quarter of the global ammonia supply. Coal-derived ammonia is considerably more carbon-intensive than natural gas-derived ammonia, with a carbon intensity in the range of 3.5–4.5 kg CO_2/kg NH_3.

recent market conditions demonstrate that natural gas is not the only driver of ammonia pricing[8]. During the 2022 fertilizer shock, U.S. ammonia prices rose sharply even though Henry Hub gas prices were materially lower than European and Asian gas benchmarks; the Energy Information Administration (EIA) noted that the global ammonia market is highly interconnected and that U.S. ammonia prices track international benchmarks in part because imports can be price-setting at the margin. USGS estimates the average U.S. Gulf Coast ammonia price was $1,070 per short ton in 2022, declining to ~$440–$470 per short ton in 2023–2024 and ~$450 per short ton in 2025**.** Farmer-paid retail prices also reached record highs in 2022 (USDA Economic Research Service reports anhydrous ammonia peaking above $1,600/ton, while even higher prices have been realized in regions particularly disadvantaged from a logistical perspective).

Finally, regional delivered prices in the Midwest will normally exceed benchmark Gulf Coast pricing because transportation, storage, and distribution can add significant basis and volatility (Figure 14 and Figure 15). Analyses focused on Upper Midwest supply chains note that logistics and distribution costs can reach hundreds of dollars per ton, in some cases exceeding $300/tNH$_3$, depending on routing, constraints, and mode of delivery. Today's prices, after the major market disruption of 2022-2023 have stabilized (FOB Gulf Coast) at around $450-$500/ton while delivered prices in Illinois as described by Farmdoc daily stabilized at around $750-800/ton confirming the noted spread due between the Gulf Coast and Midwest basis. While this appears to be a new stable plateau well below the peaks of the 2022-2023 crisis, it also indicates a permanent shift to higher prices.

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[8] A 2024 Texas A&M AFPC briefing summarizes the industry view that natural gas accounts for roughly 70–90% of variable production cost for nitrogen fertilizer, but also shows that the embedded natural-gas value explained only about $138 (≈19%) of the >$700/ton anhydrous ammonia price increase from April 2021 to April 2022, implying that other market factors drove most of the price move. The authors put the point more sharply in the conclusion: '*Our work found that increases in the cost of natural gas prices explained less than 20% of the increase in fertilizer prices paid by producers in 2022*' (p. 16). That observation remains pertinent at the time of writing of this report: U.S. fertilizer prices are rising in the wake of the 2026 Hormuz disruption even as domestic natural gas prices remain low, again consistent with the AFPC finding that gas costs are not the dominant driver of fertilizer-price movements at the farmgate (Fischer, 2024)

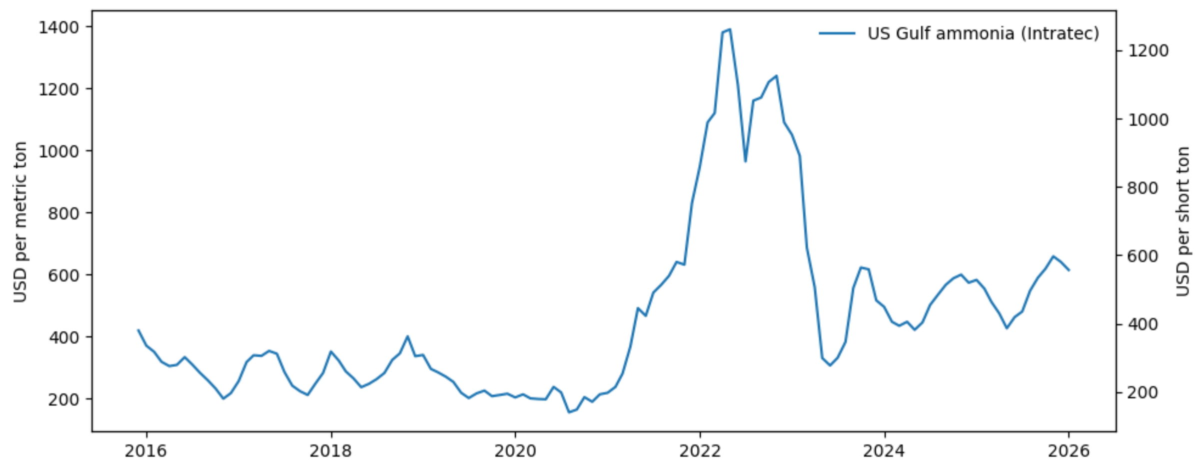

Figure 14: U.S. Gulf ammonia price (2016-to date) (Intratec, 2026).

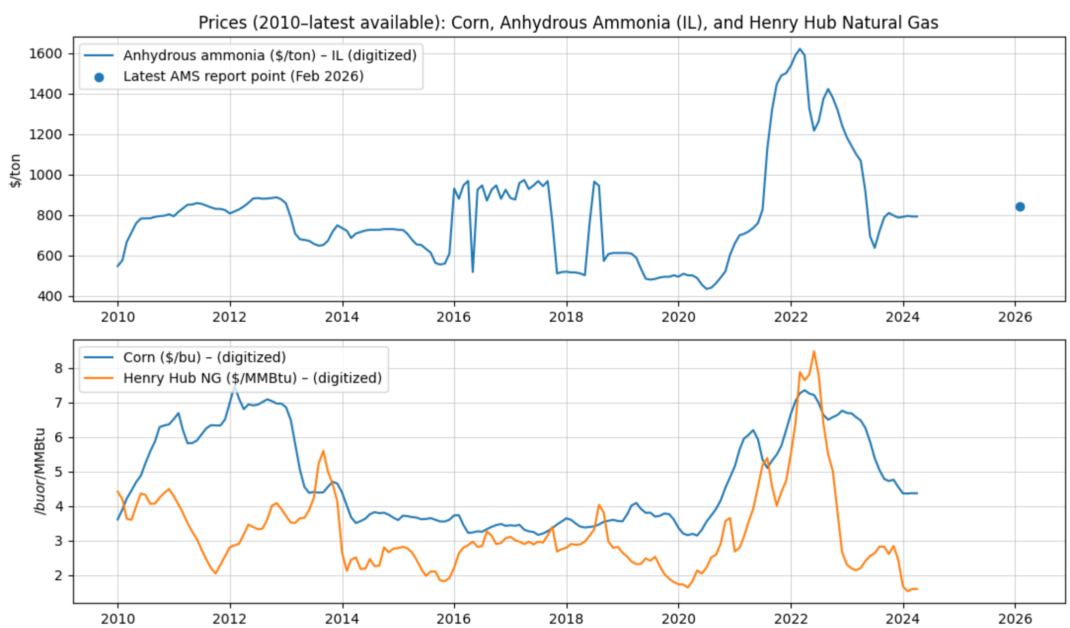

Figure 15: Midwest AA prices, Corn, and Henry Hub Natural Gas Price (2010 to 2024) (U.S. Energy Information Administration, 2026).

In the earlier release of this document, we based the economic analysis of green ammonia production on comparing its cash and LCP with those of a plant larger than the distributed green-ammonia scales examined elsewhere in this report. Specifically, we used an 85,000 mt/year plant as a benchmark because that is approximately half of Minnesota's annual direct anhydrous ammonia consumption of roughly 177,000 metric tons per the most recent reporting year (Minnesota Department of Agriculture, 2025). This provides a meaningful state-scale benchmark size without imposing capital or hydrogen-supply requirements that would be unrealistic at this stage of industry build-out. While such a plant is smaller than a world-class ammonia plant, we have determined that the comparison is skewed. The conclusion of that study indicated that the current best opportunity for green ammonia plants lies in small, localized production facilities operating in close proximity to — or within — ammonia demand clusters. These plants would have capacities of roughly 10,000–20,000 mt/year (tens of tonnes per day), an order of magnitude smaller than the 85,000 mt/year benchmark used previously and one to two orders of magnitude smaller than world-class facilities of 500,000 mt/year or more.

Under these conditions, a conventional plant-gate levelized cost of ammonia (LCOA) comparison between small-scale green ammonia and much larger gray ammonia plants is structurally bound to a negative conclusion — regardless of how well the green system is engineered — because gray ammonia remains advantaged on multiple dimensions at once:

- **Economies of scale:** Large ammonia facilities dilute fixed costs, utilities, and staffing across very large throughputs and are often integrated with low-cost feedstock supply chains.
- **Capital history:** Many incumbent gray assets have already recovered most of their capital (or benefit from accelerated depreciation schedules), so their cash cost can be materially lower than the full-cycle cost that a new entrant must recover. This disadvantage is compounded by the fact that electrolyzers remain a niche product that has not yet benefited from the cost reductions expected with manufacturing scale-up, imposing a first-mover penalty on early projects.
- **Feedstock advantage:** The lowest-cost gray producers sit on structurally inexpensive gas and/or enjoy advantaged logistics into export channels, setting a global reference price that smaller projects will not reliably beat at the factory gate.

As the economics section of this report establishes in more detail, the binding constraint for small distributed green plants is not electricity cost but capital cost per ton — and capital cost per ton is precisely the dimension on which scale most directly disadvantages a distributed approach. A like-for-like plant-gate LCOA comparison therefore measures the wrong thing; the relevant comparison is between *delivered* costs into a localized demand cluster, where the small green plant's siting advantage and the avoided transport, storage, and handling costs of long-haul gray ammonia can be brought into the calculus.

The goal of this work is not to understand "when does green beat the cheap incumbent at the plant gate," because the answer will be 'not soon.' While that question is real, it is not the framing decision question for a regional Minnesota or Upper Midwest strategy. In Minnesota and other inland agricultural markets, buyers do not purchase ammonia at the Gulf Coast plant gate. They purchase delivered products into a seasonal, logistics-constrained distribution system where a $300/ton spread over the Gulf price is typical—and often higher. This "logistics wedge," which is also a supply security risk, is the central economic opening for strategically located green ammonia in the foreseeable future: a local plant does not need to beat the global low-cost producer on plant-gate LCOA. It needs to beat the delivered cost of the incumbent supply, including transportation, storage, handling, financing charges, and regional basis. In other words, the economic analysis is intentionally framed around local delivered competitiveness, not global commodity dominance. The objective is to demonstrate that the green plant's levelized cost of production is within striking distance of the locally delivered cost of gray ammonia into the target market.

Local delivered competitiveness can be driven by the variable cost opportunity that regional renewable energy production affords the green ammonia pathway. The pathway's dominant variable cost is electricity. The opportunity is not simply that "renewables are cheap on average," however true that may be, but that wholesale power can be extremely low (or even negative) during certain periods in renewable-heavy regions, especially when transmission is constrained, and generation would otherwise be curtailed. The project thesis, therefore, focuses on access to opportunistic, inexpensive power and on designing the plant to exploit that power when it is available. Because renewable power in the Upper Midwest is indeed reasonably inexpensive, access to curtailed power—or power that would not be produced otherwise because of insufficient demand or transmission congestion—does not need to be the sole source of renewable electricity for the plant. When available, curtailed power can contribute to considerably lowering the average price of electricity delivered to electrolyzers.

This comes with a non-negotiable technical and economic tradeoff: hours of variable renewable power curtailed or not, usually imply lower utilization, and lower utilization drives up capital cost per ton. While mitigated by design choices (storage, flexibility, modularity, etc.), this impact cannot be eliminated. The tradeoff is easily demonstrated: assuming renewable power is available 35% of the time implies roughly a threefold increase in electrolyzer capacity, plus adequate hydrogen storage to support a given daily ammonia output when the ammonia synthesis loop has no or very limited turndown capacity and must be operated constantly at or near nameplate capacity[9].

Lastly, the use of curtailed power—and renewable power in general under the provisions of the 45V tax credit for clean hydrogen (though the 45V eligibility window has been materially shortened by legislative changes in 2025 and qualification rules remain restrictive; see APPENDIX

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[9] Thermo-catalytic processes like the Haber-Bosch ammonia synthesis loop are not easily ramped up and down. Start-up is lengthy, and the process has traditionally operated very inefficiently below 80–85% of design capacity. Electrolysis, by contrast, is essentially a "light-switch" process that can be ramped rapidly. Conventionally, load balancing between the two is achieved by maintaining a buffer of stored hydrogen to ensure that the ammonia loop remains fed when the electrolyzers are unavailable or operating at reduced output. However, pressurized hydrogen storage is expensive and, at large scale, can be a significant cost factor. Several major ammonia technology licensors—including Casale, KBR, Topsoe, and ThyssenKrupp Uhde—have developed flexible synthesis loop designs that claim turndown to as low as 5–10% of nominal capacity, with ramp rates on the order of 30 minutes to one hour across the full operating range. Casale, for example, has reported operation at as low as 10% of nominal capacity with ramping in the 10–100% range in approximately 30 minutes. If a flexible ammonia loop can ramp down to follow electrolyzer output rather than requiring constant full-rate feed, the hydrogen buffer storage requirement is significantly reduced—or potentially eliminated—shifting capital cost away from storage and toward a more cost-effective overall system. Until very recently, no commercial-scale flexible ammonia plants were in operation, and these claims had not been demonstrated under sustained commercial conditions. That changed in 2024–2025 with the startup of Topsoe's REDDAP demonstrator (~5,000 t/yr) at Lemvig, Denmark, and the first phase of Envision Energy's Chifeng renewable-ammonia complex (~320,000 t/yr) in Inner Mongolia, which made its first commercial green-ammonia export shipment in Q4 2025. Sustained operating data from these plants — particularly on long-term equipment fatigue under load cycling, catalyst lifetime under dynamic feed, and round-trip energy penalties associated with frequent turndowns — remains limited in the public domain and will be a critical input to future techno-economic assessments.

3: Incentives and Policies for a detailed discussion)—requires strategic siting of the asset. The location must be suitable for both accessing adequately sized local markets and securing suitable supplies of renewable power. That is why the core economic analysis should be framed as an optimization of location, achievable utilization, and the cost of the flexibility required to exploit low-price hours—not as a single average-price LCOA. (APPENDIX 2: Using Curtailed VRE Power for Green Ammonia describes in more detail what curtailed power is and the locations where it could be accessed in the context of this analysis.)

Even after accounting for avoided logistics costs, small-scale green ammonia will often face a residual gap relative to incumbent-delivered supply—especially in benign commodity years and until electrolyzer costs decrease substantially. That gap can be closed (or partially closed) through:

- **Policy incentives** (federal and/or state) tied to clean hydrogen or ammonia production, emissions performance, or rural development outcomes; and/or
- **Market premiums** (explicit "green premium" contracts, low-carbon procurement, or supply assurance contracts) where buyers value emissions reduction, supply reliability, and price stability. For example, an ethanol plant may be willing to pay a premium for low-CI corn grown with green ammonia if doing so lowers the carbon intensity of its ethanol and enables access to higher-value markets such as sustainable aviation fuel (SAF); and/or
- **Innovative offtake agreements** offering fixed-price ammonia supply, which would remove much of the price volatility that buyers currently face. Such agreements are made possible by local market access, reduced logistics costs, and—most importantly—less variable input costs and supply chain dependency compared to conventional incumbents

The analysis will therefore treat incentives and premiums as a bridging mechanism with explicit technical conditions—not as an assumption that permanently replaces competitiveness. The point is to identify the size of the gap, when it narrows, and which technical levers (e.g., electrolyzer CAPEX, cycling tolerance, hydrogen storage cost) most directly determine whether the gap can close for a defined local market.

Beyond pure delivered-cost arithmetic, a regional green ammonia strategy targets outcomes that commodity supply chains do not optimize for:

- **Supply assurance and reduced geopolitical exposure:** Shorter supply chains reduce exposure to global disruptions and import-driven price-setting dynamics, whose impact in 2022 and 2026 was significant. This, in conjunction with innovative contracting structures, could lead to long-term price stabilization.
- **Rural value capture:** Local production keeps more of the value chain—operations, maintenance, energy procurement, and potentially ownership or participation models—within rural communities rather than exporting those dollars to distant production hubs. An additional local value dimension is the recovery of local tax revenues from electricity generation that would otherwise be curtailed; when power is not produced, those taxes —typically destined to the county hosting the generating asset — are not collected.
- **System resilience:** Distributed production can reduce dependence on long, multimodal logistics corridors and can improve responsiveness during peak seasonal demand. RMI (Rocky Mountain Insitute, 2024), (Munasinghe, 2024) frames this directly as shifting supply chains from "thousands of miles" to local distribution networks, improving reliability while reducing cost and complexity. Additionally, while outside the scope of this work, operating an ammonia plant as a variable, on-demand load can contribute to grid reliability by absorbing power that might otherwise need to be curtailed.
- **Alignment with Minnesota's resource-demand match:** In the earlier version of this report, we noticed the "good match" between renewable resource potential and local ammonia demand (Figure 17) which is precisely the structural condition that makes this a plausible regional strategy rather than a generic decarbonization aspiration.

With the scope defined as regional delivered competitiveness, the core modeling should answer a small number of decision-grade questions:

- **Delivered benchmark:** What is the realistic delivered cost of ammonia into Minnesota when regional basis and logistics are included (including the $300+/ton tail cases)?
- **Local green delivered cost:** Under what combinations of (a) electricity price profile, (b) electrolyzer installed cost, and (c) utilization/flexibility strategy can a plant in the tens-of-tons-per-day range produce competitively for a local "captive" market (i.e., without relying on long-distance logistics)?
- **Gap to close:** When a gap remains, how large is it by scenario, and what level or type of incentive or premium is required to close it?
- **Technical conditions for closure:** Which technical variables dominate the outcome (electrolyzer cost, ramping/cycling constraints, storage cost, plant turndown, etc.), and what performance envelope is required for local-market parity?

That framing supports the core objective: not to ”beat the world” at the plant gate, but to fully exploit local captive markets by replacing an expensive, fragile logistics chain with strategically located production and opportunistic, low-cost curtailed renewable power — while quantifying what incentives (if any) are still required, and under what technical conditions they can be phased out. It should be noted that this report does not address this problem in its entirety: critical components such as the actual price, availability, and geographic distribution of curtailed power are beyond its scope. This analysis, however, aims to identify the framing and baseline benchmarks needed to inform future, more detailed work.

Levelized Cost of Production

The Levelized Cost of Production (LCP) is the minimum selling price at which revenue exactly covers all operating costs and provides the desired rate of return on the capital invested over the economic life of the asset. The LCP is calculated as follows:

LCP = Operating Cost per Unit of Product (Fixed + Variable) + Capital Recovery

where Capital Recovery (CR) is:

CR = Capital Recovery Factor × Specific Capital Cost

Specific Capital Cost is defined as the total capital investment divided by the annual production capacity (expressed in \$/ton-year). The Capital Recovery Factor (CRF) is a function of the desired rate of return (*i*) and the economic life of the asset in years (*n*):

$$CRF=\frac{i\,(1+i)^n}{(1+i)^n-1}$$

The CRF converts a lump-sum capital investment into an equivalent uniform annual payment that covers both the return *of* capital (analogous to depreciation) and the return *on* capital (the investor's required profit). It can be shown that as *i* approaches zero, CRF converges to 1/*n*—equivalent to straight-line capital recovery with no return on investment—illustrating that the CRF generalizes simple depreciation by incorporating the time value of capital. In the report, the Levelized Cost of Hydrogen (LCOH) and Levelized Cost of Ammonia (LCOA) explicitly tie to specific products to avoid confusion.

Green Ammonia Economics

As discussed earlier, hydrogen is the dominant variable input cost in ammonia production across all “colors” (gray, blue, green) and typically accounts for most of the cash cost of ammonia. In practical terms, understanding ammonia economics largely means understanding hydrogen economics.

Hydrogen economics

Conventional gray ammonia uses hydrogen produced via steam methane reforming (SMR) of natural gas. SMR is a mature, available technology, that is widely deployed at large scale, where integration and economies of scale drive the lowest costs. At smaller scales, SMR is still technically feasible, but unit costs generally increase as efficiency and integration opportunities decline. For context, Henry Hub spot prices have been volatile in early 2026 (weekly values roughly 3–5 $/MMBtu in February 2026) (U.S. Energy Information Administration, n.d.), and this volatility directly propagates into the cash cost of SMR hydrogen.

At current natural gas prices, gray hydrogen production costs are commonly assessed in the low single-digit $/kg range, depending on plant size, capacity factor, financing, and whether the estimate reflects production costs or a merchant-delivered price. Any specific point estimate (for example, $1.60–$1.75/kg) should be explicitly tied to a stated gas price basis, plant scale, and cost boundary (plant-gate production cost vs contract/merchant price). (U.S. Department of Energy, 2025). Forecasts for the next two years indicate fundamentally flat gas prices (Energy in Information Agency, 2026) subject only to seasonal variation, so it is prudent to assume that conventional hydrogen and ammonia costs will not change either.

Large, integrated ammonia facilities can achieve better cash-cost positions than “standalone” benchmarks because they dilute fixed operating costs and may benefit from site integration and legacy capital (fully or largely depreciated assets). In the U.S. Gulf Coast, hydrogen supply is also supported by large industrial networks and dedicated pipeline infrastructure operated by major industrial gas companies (such as Air Products). This network context is relevant when interpreting published Gulf Coast contract hydrogen prices, which may reflect merchant pricing and network economics rather than pure production cost. Nonetheless, merchant prices provide a good indication of the economics of hydrogen from natural gas, as shown in Figure 16, which also illustrates the strong correlation between natural gas and hydrogen prices.

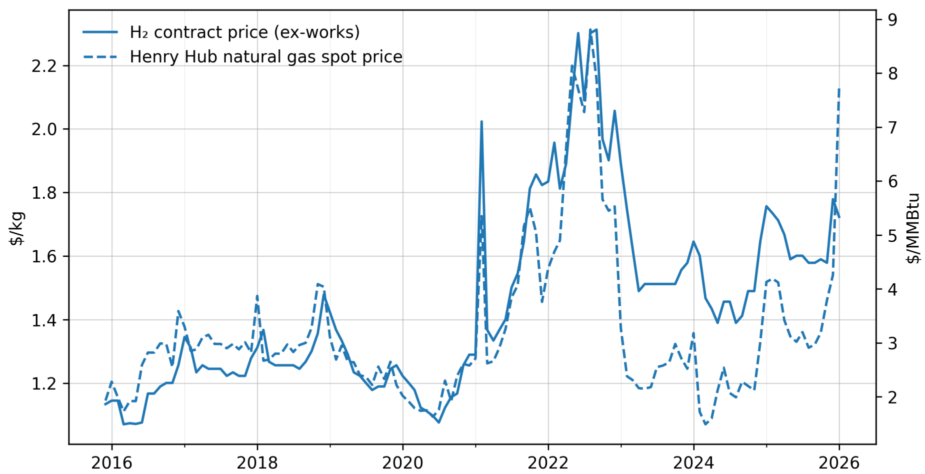

Figure 16: Gulf Coast hydrogen merchant prices and Henry Hub Natural gas prices (Sources: (Intratec, 2026) and U.S. Dept. of Energy).

The capital intensity of green hydrogen production via water electrolysis is driven primarily by the electrolyzer system (stack plus balance-of-plant (BoP)), so electrolyzer CAPEX is typically the central lever in techno-economic analysis. (International Energy Agency, n.d.) Electrolyzers are devices that split water into hydrogen and oxygen, and commercial water electrolysis is commonly grouped into four technology families: alkaline (liquid alkaline electrolyte or simply alkaline), PEM, anion exchange membrane (AEM), and solid oxide electrolysis (SOEC). Electrolyzer costs are commonly quoted in $/kW (sometimes $/kWe), but it matters whether a number refers to (i) the uninstalled "system/package" cost or (ii) total installed capital cost, which adds site installation and integration costs (civil, electrical, interconnect, EPC[10], and owner's costs).

An analysis by the Department of Energy (DOE) illustrates that early deployments can have total installed costs on the order of roughly 2× the uninstalled system cost, with this "installation multiplier" expected to decline as projects move from first-of-a-kind to nth-of-a-kind execution. As of the mid-2020s, the IEA reports installed CAPEX ranges of roughly USD 2,000/kW for alkaline and USD 2,450/kW for PEM systems, while Chinese alkaline systems can be materially lower (about USD 750–1,300/kW). [1]

[10] EPC: Engineering, Procurement and Construction.

Consistent with that picture, the DOE notes that total capital costs reported for recent PEM deployments span roughly $1,400–$2,500/kW, and that increases relative to earlier projections have been driven mainly by installation costs rather than underlying equipment costs. Within the electrolyzer system cost, the stack (the electrochemical cell assembly where electrolysis occurs) and the electrolyzer package (the physical housing of the stack with all its ancillary equipment) is typically around half of total system cost, with the remainder in BoP (power electronics, separation and processing hardware, thermal management, water handling, controls, and packaging).

Material choices affect both absolute cost and the stack/BoP split: PEM stacks include platinum-group metals (iridium and platinum) and other corrosion-resistant components, while alkaline systems can use more conventional, non-noble materials but require electrolyte handling that adds BoP complexity. Stacks are life-limited: DOE uses replacement intervals on the order of 60,000–80,000 operating hours for mature low-temperature systems (years depending on utilization), so stack replacement should be treated as a recurring capital expense rather than a negligible operating cost. In considering the final project cost, one needs to consider compression and storage needs, utilities, contingencies, Engineering, Procurement and Construction (EPC) costs, and other owner costs, which can easily add up to 40% to the electrolyzer package installed cost.

Cost trajectories are increasingly entangled with U.S. policy timing: the 45V clean hydrogen production credit is governed by final Treasury/Internal Revenue Service (IRS) regulations published January 10, 2025, and subsequent legislation (Public Law 119-21, signed July 4, 2025) eliminates 45V for facilities beginning construction after 2027, materially shortening the eligibility runway relative to the original horizon. In practical terms, a shorter 45V window increases schedule and financing risk for projects whose economics depend on that credit. This has reduced the number of viable projects and the expected ramping up of domestic manufacturing of electrolyzers has not materialized and, in turn, neither have the expected capital cost reductions (APPENDIX 1: Proposed Expansions in Ammonia Production Since 2022 And Current Status of the Industry).

Lastly, implementation rules have materially limited the fleet of renewable power generators eligible for 45V status, further limiting the viability of many proposed projects (APPENDIX 3: Incentives and Policies for Green Hydrogen and Ammonia). Table 2 indicates the assumptions used for our baseline model. These numbers are based on a 100MW installed baseline and do not include utilities, hydrogen storage, EPC costs, owners' costs, and other local fees and costs, which can increase the cost of the turn-key plant by another 30% to 40%, depending on local conditions.

Table 2: Specific power consumption and cost of alkaline and PEM electrolyzers. Utilities, EPC, and other project costs are not included.

	Specific Energy Consumption (KWh/kg H2)	Stack CAPEX ($/kW)	Electrolyzer package CAPEX ($/kW)	Total Electrolyzer ($/kWh)	Balance of plant CAPEX ($/kW)	Total Electrolyzer ($/kW)[1]
Alkaline[11]	52	$260	$380	$640	$460	$1,100
PEM[12]	50	$450	$520	$970	$630	$1,600

[11] Commercial; lower cost, lower dynamic range
[12] Commercial; fast response; higher stack cost

Levelized cost of Hydrogen (LCOH)

Based on the assumptions in Table 2, we estimate the levelized cost of producing 9,000 tons per year (tpa) of renewable hydrogen, which is sufficient to supply a 50,000 tpa ammonia plant. To put this scale in perspective, a 50,000 tpa plant would represent roughly one-third of current Minnesota ammonia demand (Minnesota Department of Agriculture, 2025). In agronomic terms, assuming an average application rate of 170 lb N/acre (University of Minnesota Extension recommends 135–200 lb N/acre (University of Minnesota Extension, n.d.) (University of Minnesota Extension, 2025), the ammonia output could support approximately 480,000 acres. At typical yields, this area could produce about 95.3 million bushels (Mbu) of corn (USDA NASS, 2025) (USDA NASS, 2025), which is sufficient to produce approximately 270 million gallons of ethanol, or about 20% of Minnesota's annual ethanol production (approximately 1.4 billion gallons per year (Minnesota Bio-Fuels Association, n.d.)).

The levelized cost of hydrogen (LCOH) is calculated assuming a 20-year project life and a 10% hurdle rate[13]. The dominant operating cost is electricity; we evaluate five power price cases: -($10), $0, $10, $20, $30, and $40 per megawatt-hour (MWh), Table 3. In this analysis, we assume a nominal 35% capacity factor. While $30–$40/MWh are reasonable benchmark ranges for renewable electricity, we extend the sensitivity to lower values, including zero and

[13] A hurdle rate is the minimum acceptable rate of return on a project or investment, used as a threshold for go/no-go decisions. If the expected return (typically measured by IRR, or by NPV discounted at the hurdle rate) exceeds the hurdle, the project clears the bar; if not, it's rejected. A few nuances are worth keeping in mind, especially for this kind of early-stage or first-of-a-kind project. The hurdle rate is usually set at or above the project's weighted average cost of capital (WACC), with an added risk premium reflecting theproject's specific risk profile — technology maturity, feedstock supply risk, offtake certainty, policy/incentive durability, etc. For a first-of-a-kind project, hurdle rates are often noticeably higher than for a proven, contracted asset. It's distinct from the discount rate in a strict sense: the discount rate is what you use to compute NPV (often = WACC), while the hurdle rate is the decision threshold. In practice, many companies use them interchangeably, but a sophisticated investor will set a hurdle above WACC to account for project-specific risk and to maintain a portfolio risk-adjusted return target. This is particularly acute for projects such as green ammonia.

negative prices. These outcomes can occur during periods of curtailment, when supply exceeds local grid capability or demand and generators are forced to reduce output.

We also quantify the impact of the utilization factor (capacity factor) in Table 5, while Table 4 shows the impact of the technology choice. Only Alkalyne and PEM electrolyzers are included since Solid Oxide and AEM electrolyzers are not currently commercially available at a meaningful scale.

Table 3: Sensitivity of LCOH to the price of electricity under various electricity price scenarios

Power Price ($/MWh)	($10)	$0	$10	$20	$30	$40
LCOH ($/kg)	$4.21	$4.74	$5.28	$5.81	$6.34	$6.88
Electricity % of LCOH	-12.0%	0.0%	10.1%	18.4%	25.2%	31.0%
H^2 Cash Cost ($kg)	$0.99	$1.53	$2.08	$2.59	$3.13	$3.66

Lower utilization increases the effective capital intensity because more installed electrolyzer capacity is required to achieve a given annual (or daily) hydrogen output, while that equipment operates fewer hours per year. Lower utilization also increases hydrogen storage requirements to buffer intermittent hydrogen supply to the Haber-Bosch process, which further increases total capital cost.

This analysis does not explicitly model differences in dynamic response between proton exchange membrane (PEM) and alkaline electrolyzers. Slower ramp rates and longer start-up transients can reduce delivered throughput during short operating windows because the electrolyzer spends a larger fraction of each run below nameplate capacity. In most cases, this effect is second-order relative to electricity price, capacity factor, and storage sizing; it should be addressed in project-specific design but does not materially change the conclusions of this screening-level analysis.

An appendix provides additional details on curtailed VRE power and the opportunities it offers. The key constraint is that curtailment is highly localized and market-structure dependent: availability and pricing are tied to specific generation clusters, congestion points, and distribution or transmission nodes. As a result, any project seeking to rely on curtailed electricity must be sited deliberately, typically within established generation corridors. These corridors are generally located in regions with high-quality wind or solar resources, where most existing generation is already concentrated and where incremental build-out is also expected. The Appendix discusses the underlying drivers of curtailment, potential system-level benefits (beyond opportunistically low energy prices for the off-taker), and the requirements for identifying viable interconnection points.

For the purposes of this report, it is sufficient to note that, as shown in Figure 17, there is substantial overlap between (i) areas with high renewable generation potential and a correspondingly higher likelihood of curtailment and (ii) areas with significant ammonia demand.

A 50,000 tpa ammonia plant (approximately 140 tons per day) is small relative to a conventional world-scale facility, but it is large enough to have a meaningful local impact and to support an ammonia synthesis loop that begins to capture economies of scale[14]. Its associated hydrogen production would require on the order of 50–55 MW of average electrical power; at the assumed 35% capacity factor, which corresponds to an electrolyzer installation with nameplate capacity of 140–160 MW. These requirements must be evaluated against local interconnection capacity and congestion constraints, which, in turn, makes proximity to established generation corridors a critical siting criterion, regardless of whether curtailed power is used.

While access to curtailed electricity could materially reduce the blended power cost, a plant of this scale is unlikely to operate exclusively on curtailed energy and will typically require a

[14] 50,000 tpa of ammonia equates to approximatively 140 tpd. This is on the very low end of what some vendors consider economically viable, although there is ample debate on this limit and how it will evolve among the ammonia technology providers community.

mix of curtailed and market-priced electricity (or contracted supply). Maximizing the value of curtailed power, therefore, becomes a coupled sizing-and-siting problem: the optimal plant scale depends on the local curtailment profile and deliverable energy at the point of interconnection, as well as the cost and feasibility of supplementing with non-curtailed power.

The overlap between generation corridors and ammonia demand makes curtailed-power-enabled ammonia production a credible siting concept and worth further evaluation in the next stage of economic and project development analysis, as outlined in the Appendix.

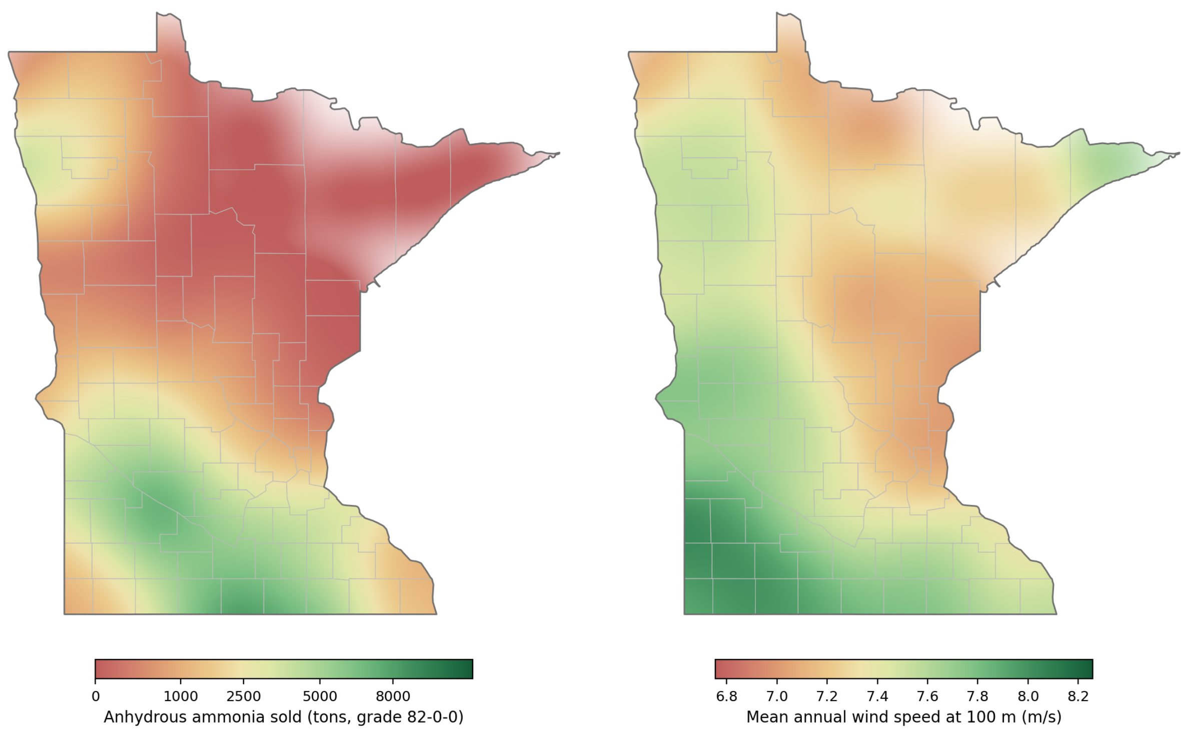

Figure 17: County-level comparison of nitrogen fertilizer demand and wind resource across Minnesota. The left panel maps anhydrous ammonia sales (grade 82-0-0) by county for the 2024 crop year (207,495 tons statewide); the right panel maps long-term mean wind speed at 100 m hub height. The high-wind southwest — the Buffalo Ridge counties of Lincoln, Murray, Pipestone, Nobles, and Cottonwood — coincides with the state's highest anhydrous ammonia demand, indicating favorable geography for co-locating green ammonia production near both the wind resource and existing fertilizer offtake. Anhydrous ammonia data: Minnesota Department of Agriculture, 2024 Crop Year Fertilizer Sales Report*, Wind data: National Renewable Energy Laboratory, Wind Integration National Dataset (WIND) Toolkit (2 km resolution, 2007–2014), via data.openei.org. Map created by the Agricultural Utilization Research Institute (AURI).*

Table 4: LCOH of hydrogen for Alkaline and PEM Cell. Assume 9,000 tpy hydrogen production, sufficient for a 50,000 tpy ammonia plant.

Unsubsidized LCOH ($/kg)	**$5.81**	**$7.86**
Power cost ($/MWh)	$20.00	$20.00
Capacity factor %	30%	30%
Technology	Alkaline (AEL)	PEM
Installed MW	127.45	122.55

Component	$ / kg	% of LCOH	$ / kg	% of LCOH
CAPEX (annualized)	$3.22	55.4%	$4.49	57.1%
Electricity	$1.07	18.4%	$1.03	13.1%
Water & wastewater	$0.00	0.1%	$0.00	0.1%
Fixed O&M	$0.82	14.1%	$1.15	14.6%
Stack replacement	$0.65	11.2%	$1.14	14.5%
Other variable O&M	$0.05	0.9%	$0.05	0.6%
Unsubsidized LCOH ($/kg)	**$5.81**		**$7.86**	

CAPEX component	$/kW	% of total	$/kW	% of total
Stack	251	18.1%	436	21.7%
Electrolyzer package	366	26.5%	504	25.1%
BoP	444	32.0%	611	30.4%
Compression and Storage	27	1.9%	28	1.4%
Water treatment	3	0.2%	3	0.1%
Other project costs	294	21.3%	427	21.3%
Total ($/kW)	**1,384**		**2,010**	

	$MM	$/kW	$MM	$/kW
Total Installed CAPEX	$135.2	1,061	$190.2	1,552
Inclusive of OSBL	$138.9	1,090	$193.9	1,582
Total Project cost	**$176.4**	**1,384**	**$246.3**	**2,010**

Table 4 shows the LCOH for a 9,000 tpy electrolytic hydrogen project, assuming a 20-year project life and a 10% discount factor. The total project cost is higher than the total installed CAPEX, as it includes elements often ignored in other analyses, such as EPC costs, fees, and insurance, and owner's costs, including initial working capital. At a $20/MWh average electricity price, electricity — while a significant portion of the overall hydrogen cost and certainly the most important variable cost — is not the highest cost component; the capital cost is. PEM remains considerably more expensive, and while the model accounts for its better energy efficiency, that benefit is not enough to bridge the large current capital cost gap. The high impact of capital is driven by relatively inefficient equipment utilization, as shown in Table 5, while Figure 18 indicates that LCOH is similarly impacted by capital utilization.

Table 5: Impact of utilization on LCOH.

Utilization	**30%**	**50%**	**80%**	**100%**
Total Project cost ($MM)	$176.4	$159.80	$107.30	$88.80
Unsubsidized LCOH ($/kg)	$5.81	$5.48	$4.03	$3.52
CAPEX % of LCOH	55.4%	53.20%	48.50%	45.90%
Electricity % of LCOH	18.40%	18.80%	25.50%	29.10%

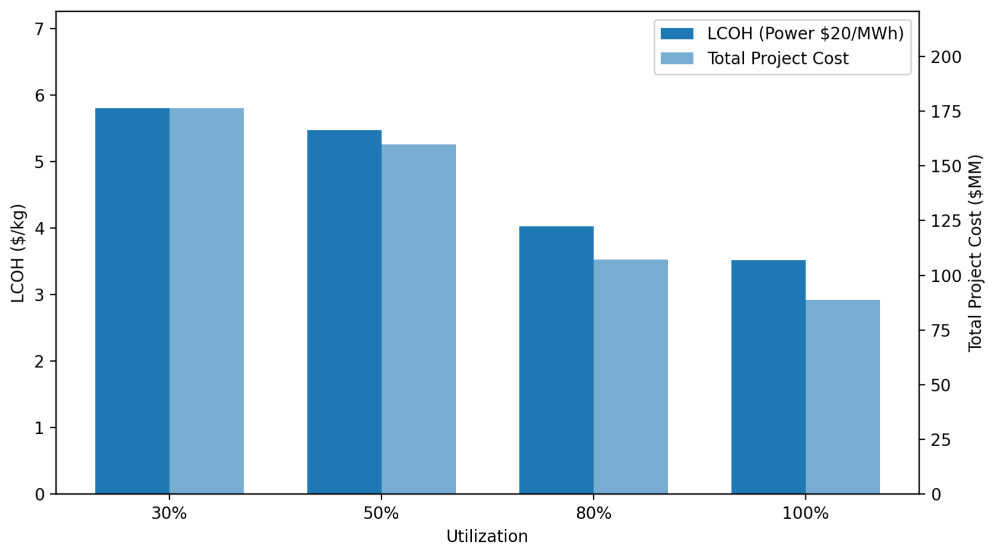

Figure 18: LCOH with different utilization factors.

These results, nonetheless, indicate that even with high utilization rates, the capital cost burden, while reduced, remains considerable, and high energy prices can easily derail a project. In fact, even with a high utilization rate, commercial energy prices in the order of $65/MWh – which today would be considered a very competitive industrial power rate - would make electrolytic hydrogen economically uncompetitive.

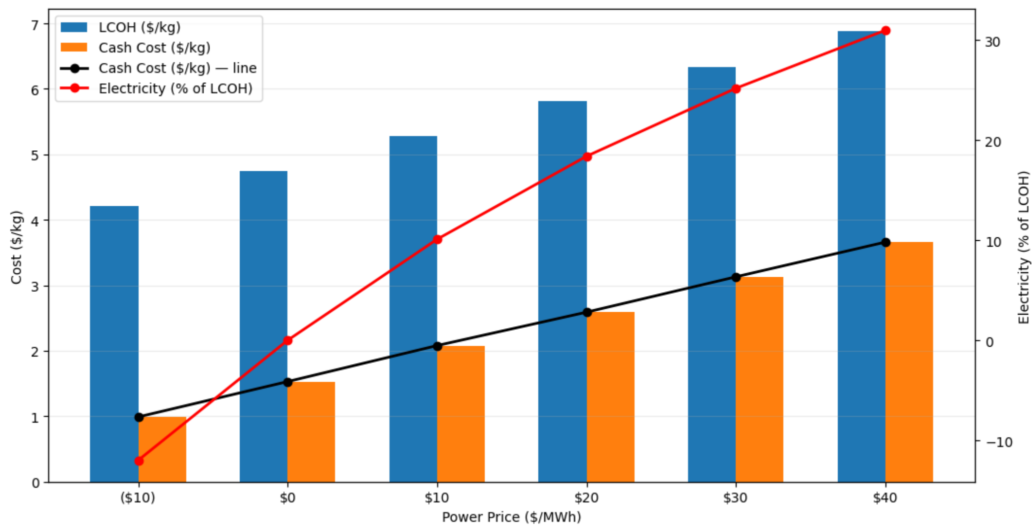

Figure 19: Sensitivity of LCOH to the price of electricity.

As Figure 18, Table 6, and Figure 19 and indicate, even if the capital cost remains the largest component of the LCOH. The cash cost of production is highly impacted by the electricity cost, so if the capital cost is reduced by 50% as expected by the industry scaling up, while the LCOH will decrease considerably, electricity will become its most significant component, and abundant and inexpensive renewable electricity will become the primary driver to viability.

Table 6: Sensitivity of LCOH and Electricity as % of LCOH to electrolyzers cost reduction.

Cost reduction of electricity from baseline	0%	25%	50%	70%
LCOH ($/kg)	$5.81	$4.67	$3.52	$2.60
Electricity as % of LCOH	18.4%	22.9%	30.3%	41.0%
Total project cost ($/kW)	$1,384	$1,047	$711	$411

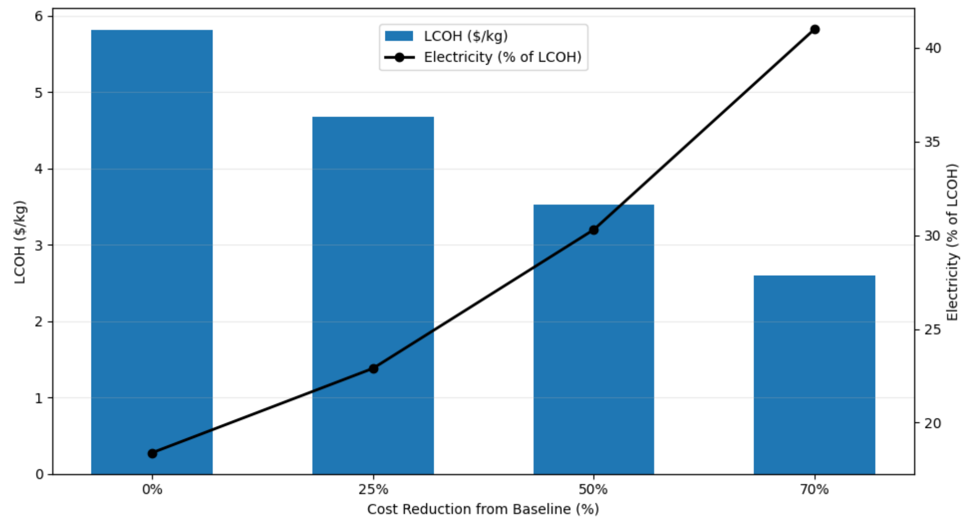

Figure 20: Sensitivity of LCOH and Electricity as % of LCOH to electrolyzers cost reduction.

Levelized Cost of Ammonia (LCOA)

To calculate the levelized cost of ammonia (LCOA), we use LCOH as a transfer price in a production cost model that adds all the other variable and fixed costs of the ammonia plant. We estimate that an ammonia plant with a stated capacity of 50,000 tpa will cost, on a turnkey basis, approximately $65.8 MM; this price is inclusive of 10 days of ammonia storage. Under these assumptions, with hydrogen transferred from a 9,000 tpa electrolytic facility at 30% capital utilization and an unsubsidized LCOH of $5.81/kg, the LCOA is estimated to be $1,227/metric ton ($1,115/short ton). Total project costs (ammonia plant + Haber-Bosch loop) are approximately $300 MM (Table 7).

Table 7: LCOA with 30% utilization of the hydrogen plant, 20 years depreciation, 10% hurdle rate, and $20/MWh electricity for hydrogen generation. (HB = Haber-Bosch).

Component	$/ton	% of LCOA
CAPEX HB Loop only (Annualized)	$161.72	13.2%
Hydrogen	$984.50	80.2%
Electricity	$35.06	2.9%
Catalyst and Chemicals	$5.00	0.4%
Other variables and O&M	$3.00	0.2%
Fixed O&M	$38.62	3.1%
Total LCOA	**$1,227.90**	

	$MM
CAPEX Ammonia (Fully Loaded)	$65.8
CAPEX Hydrogen (Fully loaded)	$234.7
Total Project cost	**$300.5**

Hydrogen accounts for the majority of both capital and operating costs. On an unsubsidized basis and with current hydrogen technology costs, the LCOA remains too high to present a compelling business opportunity given expected sale prices around $700–$800/ton. On the other hand, this is where we see the logic of the 45V tax credit. Under the most favorable carbon-intensity conditions — which electrolytic hydrogen could satisfy — up to $3/kg of hydrogen tax credit is available. Such an incentive would reduce the hydrogen cost to $2.81/kg which on an incentive free basis stands well above $5/kg. While the incentivized costs is still marginally higher than the current Gulf Coast prices enjoyed by legacy producers, it would enable an LCOA of $698/ton (Table 8), enabling it to be fully competitive in the Upper Midwest by capturing the spread between local delivered prices and the plant-gate prices of legacy producers.

Table 8: LCOA assuming a 45V $3/kg tax credit for hydrogen. All other conditions unchanged. (HB = Haber-Bosch).

Component	$/ton	% of LCOA
CAPEX HB Loop only (Annualized)	$161.72	23.2%
Hydrogen	$455.09	65.2%
Electricity	$35.06	5.0%
Catalyst and Chemicals	$5.00	0.7%
Other variables and O&M	$3.00	0.4%
Fixed O&M	$38.62	5.5%
Total LCOA	**$698.49**	

	$MM
CAPEX Ammonia (Fully Loaded)	$65.8
CAPEX Hydrogen (Fully loaded)	$234.7
Total Project cost	$300.5

The rationale behind the Inflation Reduction Act (IRA) and its 45V tax credit provision appears clear, as does the reason why the viability of green ammonia is tied to that of green hydrogen. Hydrogen is the only significant lever to reduce the LCOA — not only because of its overwhelming impact on costs, but also because ammonia synthesis technology is very mature and offers scant opportunity for further cost reduction.

Electricity cost reductions alone will significantly reduce LCOA — for example, free electricity would bring it to approximately $1,000/ton — but the most effective combination would be the cheapest possible electricity paired with a reduction in capital cost, which in turn could be achieved immediately through improved utilization. For instance, a combination of low-cost electricity — at $10/MWh from a mix of curtailed power and long-term contracted renewable power — and a 50% capital cost reduction in electrolysis or superior utilization would bring the LCOA to between $750/ton and $800/ton, again making local green ammonia competitive with current market offerings.

Viability of a distributed small to medium-scale ammonia industry

A distributed green ammonia industry is structurally exposed to the mismatch between low marginal electricity cost and a high fixed capital cost whose per-kilogram burden is acutely sensitive to utilization. The distributed concept usually implies smaller plants located near demand — fertilizer markets, co-ops, terminals. In the curtailment-driven case, generally relying on VRE, the plant is also operated flexibly to chase low or negative locational marginal prices (LMPs). That operating mode can reduce the cash cost of electricity per kilogram of hydrogen — and therefore per ton of ammonia — but it does so by lowering the capacity factor, which in this flexible mode is the single most punitive variable in the economics of capital-intensive electrolysis. The relationship is not monotonic: chasing only the cheapest hours sacrifices so much utilization that the levelized cost rises again, so the real problem is to find the capacity factor that minimizes total cost, not the lowest average electricity price. Put differently, the fully loaded hydrogen cost is less "electricity price times kWh/kg" than it is an annuity problem: until significant reductions in electrolyzer cost are achieved, or better utilization becomes possible, the levelized cost of hydrogen (LCOH) is dominated by annualized capital cost. When annual output is intentionally constrained to the subset of "good hours," the capital component per kilogram rises, often enough that capital becomes the majority of LCOH even with extremely inexpensive electricity. This is particularly acute for ammonia because the system boundary is larger than the electrolyzer. While electrolyzers account for a very large share of capital costs, a practical distributed green ammonia unit includes electrolysis, water treatment, compression, storage (hydrogen and/or ammonia), nitrogen supply (air separation or pressure swing adsorption), and an ammonia synthesis loop.

Running on curtailed power will not eliminate the VRE need for buffering and storage to decouple intermittent electricity from less-flexible downstream or upstream synthesis, which adds balance-of-plant capital. In other words, curtailment lowers variable cost but tends to increase both (a) the fraction of fixed costs and (b) the amount of "supporting" CAPEX required to make intermittency workable. While this will be ameliorated by the claimed process technology, which is said to allow rapid swings in the ammonia loop throughput, that technology is only now emerging, and only limited operating data from commercial-scale operations is available. The economic results are projects that look compelling on a cash basis but are challenged on a levelized basis unless capital costs fall materially or utilization can be stabilized without losing the low-cost electricity advantage.

In this type of development, early movers carry a disproportionate burden. Electrolyzer capital costs are expected to decline with manufacturing scale, supply-chain maturation, higher factory utilization, and standardization, but those learning-curve benefits are captured over time by industry, not by the first wave of projects. Early projects face higher equipment pricing, higher EPC risk premia, more conservative financing terms, and greater technology integration risk, while also being asked to prove out operating strategies such as flexible dispatch, environmental attribute tracking, and ammonia loop turndown that lenders and insurers do not yet treat as routine. Even if curtailed power makes electricity cheap, it does not solve the fact that a capital-heavy system with less than full utilization and evolving compliance requirements will be underwritten with a high cost of capital and tight financial covenants. That combination is exactly what makes "distributed" more difficult. While the arbitrage on a long supply chain allows an opportunity to compete on selling price; smaller scale reduces production economies of scale, with intermittent operation reducing utilization; and both forces push the cost structure toward capital rather than operating cash.

Plant-gate ammonia prices from these plants can be within striking distance of the local retail price in the upper Midwest market, but risks will make it difficult to attract the needed capital. The 45V tax credit for green hydrogen, which provides up to $3/kg in tax credits for green hydrogen production, is an incentive that can materially change the status quo, but given the relatively short remaining time horizon and the constraints of the statute, new policies and incentive structures need to be devised. Direct incentives for capital investment, to reduce the first-mover disadvantage, are as important as production tax credits. Additionally, the effective monetization of the environmental attribute of green ammonia across the value chain is needed. While that is not detailed in this report, ultimately, any measure taken needs to address a single pressing issue: halving the economic burden of hydrogen.

Final remarks on green ammonia economics

Stepping back, and in conclusion, the unsubsidized economics tell a consistent story across every scenario. At a representative baseline of $20/MWh and 30% capacity factor, the levelized cost of ammonia from a distributed alkaline-electrolyzer plant is approximately $1,228 per metric ton — materially above current delivered Upper Midwest prices and well above the plant-gate cash cost of legacy gray ammonia.

Electricity is the most visible variable cost. The temptation is to read the problem as one of finding cheap enough power —the typical narrative in most green ammonia literature. This report does not support that reading. Even at no cost electricity — the counterfactual extreme, corresponding to fully captured curtailed power with no offsetting infrastructure cost — the LCOA falls only to roughly $1,000 per ton. The residual is almost entirely capital recovery. Capex, not electricity, sets the floor.

The combinations that close the gap, therefore, involve more than electricity price alone. Low-cost electricity in the $10/MWh range, drawn from a blend of curtailed and contracted renewable supply, paired with electrolyzer capital costs roughly halved from today's installed numbers, brings the LCOA into the $750–$800 per ton range — plausibly competitive with Upper Midwest delivered gray ammonia and the threshold at which distributed green ammonia begins to make commercial sense without production credits. None of these levers is sufficient on its own; together, they are.

Capex reductions of this magnitude are not a project-execution problem but an industry-scale one, requiring manufacturing scale-up, supply-chain maturation, and the cumulative learning that the wind and solar industries went through before becoming least-cost. First-mover projects therefore bear a disproportionate share of that capital burden, which is the structural argument for capital-side incentives — investment tax credits, grants, loan guarantees, and credit enhancements — that lower the first-mover cost of capital rather than subsidizing per-kilogram production indefinitely.

APPENDIX 7 presents the supporting sensitivity analysis: LCOA responses to electricity prices, capacity factors, and electrolyzer CAPEX trajectories, along with the combined-lever scenarios that define the competitiveness frontier. Ultimately, any policy or commercial measure has to address the same structural reality: closing the gap requires both halving the capital cost of hydrogen production and securing structurally cheaper electricity, and neither lever alone is enough.

Fertilizer Distribution Hubs in Minnesota

In 2023, AURI extended a survey to 363 fertilizer distributors, retailers, and supply chain actors in Minnesota to better understand the transportation and storage channels in the state. Because Minnesota does not currently produce fertilizer, other than preparing specialty mixes, these questions are important to understand, not only the current market pathways, but also how distribution affects price. AURI received a five percent response rate, which is on par with the six percent average response rate for email surveys in the U.S., indicating that, given a relatively small sample, the results should be reasonably reflective. The Magellan pipeline, which imported AA into Mankato, closed in 2019 (Figure 21). Two large farmer cooperatives in Southern Minnesota corroborated information learned via the Minnesota Department of Agriculture's (MDA) Pesticide and Fertilizer Management representative: the vast majority of the ammonia consumed in Minnesota is delivered and distributed into the state by truck (Minnesota Department of Agriculture, n.d.) (Rocky Mountain Insitute, 2024).

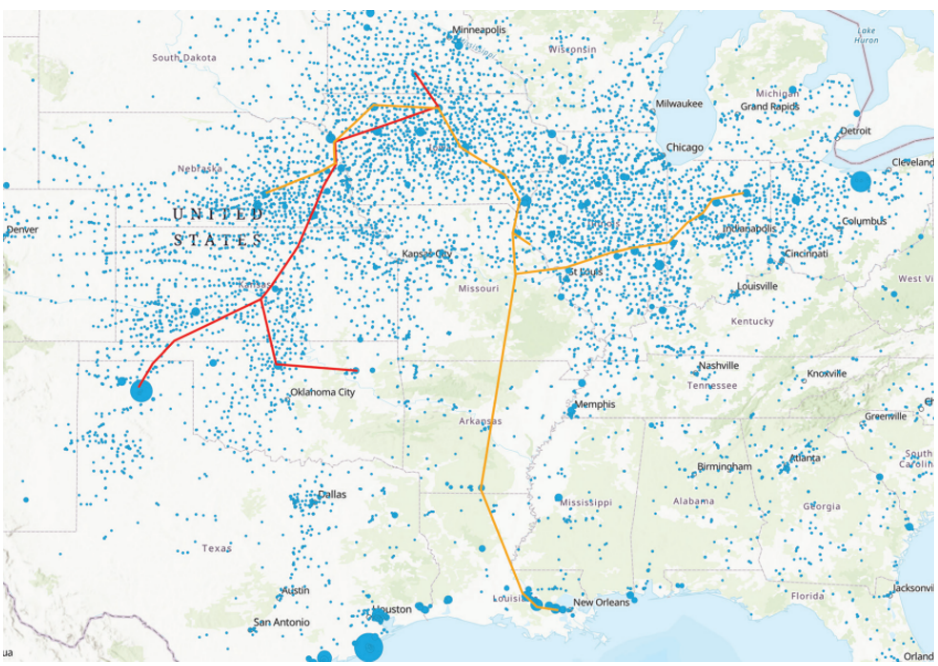

Figure 21: "Liquefied AA storage and pipeline distribution networks in the U.S. Midwest. The Kaneb (orange) and Magellan (red; decommissioned in 2019) AA pipelines are respectively 2,000 miles and 1,100 miles long." Circles indicate ammonia tonnage (The Royal Society, 2020).

Table 9: AURI Survey of Minnesota Fertilizer Market - Primary Mode of Transportation for Distributing Inputs (respondents were prompted to select all that apply).

Transportation Mode	Receiving Inputs	Distributing Inputs
Truck	68.07%	87.92%
Train	16.54%	2%
Barge	3.84%	1%
Pipeline[15]	3.84%	1%
Did not answer/Not Applicable	4%	4%
Other	0%	0%
Other: Nurse Tanks		4%

Once in the state, fertilizer is further distributed almost solely by truck (87.92%). Researchers asked respondents to describe how, if at all, distribution has changed since the 2019 closure of the Magellan pipeline, with 65% of respondents claiming an impact on their transport pathway(s). Transportation is the key indicator to higher logistics costs, followed by labor and equipment (Figure 22). Those polled also reported that transport distances have increased, and access to fertilizer is more limited and challenging to acquire. Additional barriers include higher freight rates, longer wait times, fewer transport options, and less certain supply coming from distribution terminals.

[15] It should be noted that the Magellan now ONEOK pipeline terminating in Mankato, the only ammonia pipeline reaching Minnesota, is currently not operational as it was decommissioned in 2019. On the other hand, the Kaneb/NuStar pipeline reaches Northern Iowa, and some Southern Minnesota distributors, and producers may receive their AA this way.

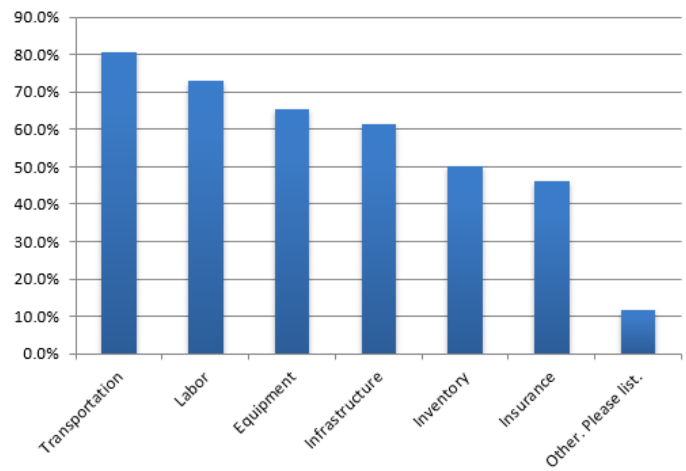

Figure 22: AURI Survey of MN Fertilizer Market - Key Costs of Logistics.

AA is a volatile compound and requires a permit for storage (unlike urea) (Minnesota Department of Agriculture, 2026). Overall, Minnesota has the capacity to store roughly one-fifth of its overall Anhydrous Ammonia (AA) fertilizer demand, indicating that the amount of fertilizer transported into the state turns over five times. Some survey respondents claim a higher tenfold turnover rate (or one-tenth of their demand) each season.

Researchers asked respondents how storage capacity impacts their costs. Most stated that the storage was a significant cost and logistical barrier, especially as fertilizer is a seasonally applied product. They also asked about the impact of seasonality on fertilizer prices. Because distributors cannot purchase at off-peak prices, increased costs are passed on to end users. (When asked about seasonal demand, retailers noted fall sales are higher, which is on track for a northern state climate, as spring weather can create unpredictable conditions, such as heavy rainfall or extended ground freeze, which delay fertilizer application and planting dates).

Table 10: AURI Survey of Minnesota Fertilizer Market – Amount of AA Sold by Season, Based on Time of Application (for example, if purchased in the fall and applied in the spring, respondents were prompted to note this as a spring sale).

Anhydrous Fall Sales: Tons	Anhydrous Spring Sales: Tons	After Planting: Tons
41,134 Tons	13,368 Tons	3,412 Tons*

When asked to briefly state their current perception of green AA, respondents were generally aware, inquisitive, and cautious. Industry thought leaders indicated farmer interest is related to situational planning and the desire for a better way to manage the volatile prices of fertilizer, especially when prices are high. Simplified marketing was seen as a means for spurring quicker adoption by farmers. There was mixed knowledge of how much capital investment would be needed to improve current storage capacity to meet future demand if green ammonia were produced and/or distributed in Minnesota. These findings indicate that more public information may be needed around this emerging opportunity.

AURI also asked whether retailers would be willing to sell green AA if it was price competitive with conventional AA, and 69.2 percent of respondents said "yes" (Figure 23). For those who noted "it depends", some respondents mentioned uncertainty over the cost to update equipment and storage capacity, whether regulations are different, and whether segregating green from conventional AA would be a factor. When asked whether they would be willing to sell green AA at a higher price, willingness to do so dropped to 11.5 percent. Personal communication by industry experts corroborated RMI's finding that fixed-price long-term offtake agreements "may pose difficulties for agricultural co-ops" because "short-term agreements are commonplace in the fertilizer market," with conventional ammonia contracts "anchored to cost and freight (CFR) Tampa spot prices" (RMI 2024, p. 30). The financing-side counterpart of this tension is documented by the USDA Agricultural Marketing Service ((USDA-AMS) which notes that banks require long-term offtake agreements to finance new ammonia projects.

Another critical implication for local distributed production of green ammonia is the current lack of AA storage. With storage turnover of five to ten times per year, local production will require considerable investment in expensive storage infrastructure. Even at price parity, it is unlikely that distributors will be motivated to bear such a financial burden, further raising the financial hurdle for project developers.

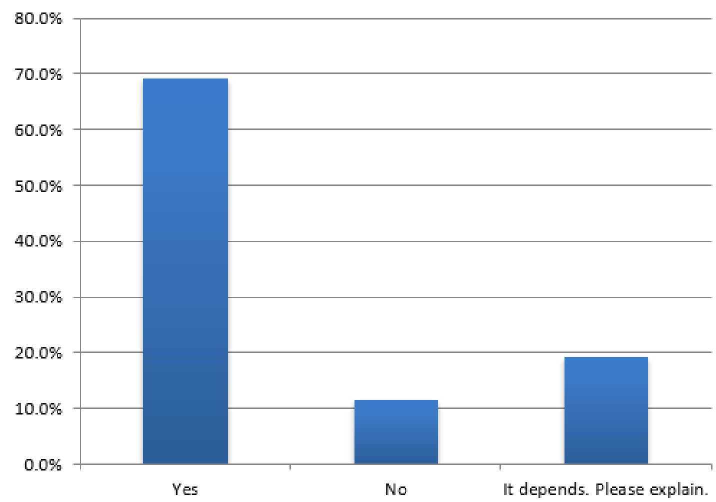

Figure 23: AURI Survey of MN Fertilizer Market - Willingness of Retailers to Sell Green AA if it were the Same Price as Current AA.

Alternative and Complementary Options to Synthetic Nitrogen Fertilizers

Farmers have concerns about both the availability and price of fertilizers (Paulson, Schnitkey, Monaco, & Zulauf, 2025), in addition to safety, performance/efficacy, ease of application, storage, transport, and convenience. There is a limited timeframe for fertilizer application in the fall, as NH_3 needs to be applied when the soil temperature is 50 degrees or less. Springtime application can be problematic, as rainy spring weather could delay planting. The interest in alternative nitrogen sources remains high, although no clear alternative to ammonia has been found to date.

Biological fertilizers gained considerable interest over the last few years. In nature, nitrogen is fixed from the atmosphere or from decaying organic matter by bacteria, which convert either atmospheric or organic nitrogen into biologically available ammonium. However, naturally occurring biological nitrogen fixation is not sufficient to provide the nitrogen needs of high-yield crops.

Available data on biologicals is scarce, and proven performance is inconsistent. Biologicals would be used mostly on corn and small-grain crops. Anecdotally, some farmers reported that biologicals do not work well when synthetic nitrogen is also applied. The general industry perception is skepticism around biologicals, though the science may catch up; more strip and whole-field trials are needed. Companies producing biologicals are diligent in their research, but getting products to work in the field involves far more variables — soils host many more microbes than the sterilized substrates used in greenhouse trials (Schütz, 2018), (Mpanga, 2024), (Illinois Corn Growers Association, 2025)

At this time, there is a low likelihood that biologicals will replace synthetic fertilizers. Biologicals offer added value but are not a drop-in replacement. The current consensus is that biologicals could replace at best 10–20 percent of the synthetic nitrogen needed for corn (e.g., most nitrogen fixers — not unlike their naturally occurring counterparts — down-regulate their N-fixation pathways once synthetic N is applied). It should be noted that this consensus lies at the conservative end of vendors' claims (C&EN, 2025). Lastly, the most promising avenue to overcome these limitations lies in gene-edited or genetically engineered organisms. Gene-edited intraspecies products (e.g., Pivot Bio's Proven series) are already commercial in the U.S., though transgenic approaches that introduce nitrogenase machinery into cereal-associated microbes remain pre-commercial. Wider adoption of either pathway, and especially of transgenic approaches, would require navigating regulatory, validation, and consumer-acceptance hurdles.

Nitrogen from manure has been used as fertilizer since humankind transitioned from nomadic hunter-gatherer societies to settled communities supported by agricultural production. Manure used in agriculture has been either fresh manure produced by farm animals or "fossilized" manure, such as the guano deposits. Until the advent of synthetic ammonia, guano was the main long-distance commercial fertilizer, transported from mining sites to farming communities. Guano and manure would not have been sufficient to sustain the last century's growth in agricultural productivity, and while guano has all but disappeared as a significant source of nitrogen, manure application remains important.

The growth of the animal protein industry has generated more manure to be managed. A United States Department of Agriculture (Porter & James, 2020) study using geospatial analysis indicates that up to 30 percent of Minnesota's nitrogen needs could be supplied by manure, but a considerable fraction of the nitrogen from manure is lost. Several factors appear to limit the current usefulness of manure. Manure is diluted and cannot be economically transported more than a few miles from its production site. Also, manure is rich in phosphorus, and while phosphorus is a needed macronutrient, its content is often high enough to become the limiting factor in manure's effective use. If nutrients in manure are not recycled, manure is a potential environmental liability due to uncontrolled methane and nitrous oxide emissions, in addition to ammoniacal nitrogen leaching into groundwater.

This report highlights the opportunity to reduce synthetic fertilizer use through improved nutrient recycling; however, it will require considerable investment in both technology deployment and adoption of novel manure management practices. The tradeoff and complementarity between these approaches, biologicals, improved manure nutrient recovery, and the development of green ammonia needs further investigation as it could drive holistic technological development.

Gaps in the Current System

As mentioned, there is a disconnect between AA production and consumption in the U.S., and such a gap is particularly relevant to agricultural states like Minnesota that do not have any local production, rely on long-distance transportation for their fertilizer supply, and have limited capacity to store ammonia. By comparison, urea is a dry non-volatile and non-hazardous product, and it does not require a permit for storage and is generally safer to apply than liquid AA (Minnesota Department of Agriculture, 2026). As recognized by industry experts interviewed by AURI, if the economics are positive, growers, dealers, and distributors would use locally sourced green ammonia. But, they must have answers to where production sites will be proposed, production levels, what the contracts look like, and an availability and commercialization timeline before committing to purchases decoupled from the usual supply chain or slowing the transition to urea. The project team identified the following gaps:

- Large differences in prices, even at the regional level, are heavily influenced by distribution logistics.
- Storage is a significant part of the logistical costs, though it is often not paid by the manufacturer. Costs and storage scarcity can lead to local inventory shortfalls and price spikes. Price volatility may make this trend worse (Transportation, Distribution, and Storage of Hydrogen, 2004).
- Higher gas prices and reduced renewable energy prices are closing the gap in the cash cost of green hydrogen, and hence green ammonia, but the capital needs for the establishment of green ammonia production remain high.
- Ease and flexibility of urea in field application, safety, and the regulatory burden of ammonia handling reduce the end-user demand for AA.
- Poor utilization of recycled and recyclable nutrients.
- A lack of policy recommendations and guidelines when it comes to improving the reliability and carbon intensity of the fertilizer supply chain.

Data exists to support the variance in the cost of ammonia at the Gulf of Mexico, costs added for shipping from Oklahoma, and the export price being lower than that paid in Minnesota due to the logistics. This price variance could serve as a proxy for Midwest prices of between $300-$500 per ton. (ITL, 1/24/23).

Environmental Cost/Benefit Analysis

Synthetic fertilizers, because of their immense impact on increasing global crop yields, thus food security, present an environmental paradox (Ritchie, 2021). Increased yields mean land is more efficient, creating an environmental benefit since farmers need less space to grow comparable – or more – quantities of food. Alternatively, over- or improperly applied, synthetic fertilizers can lead to nitrogen losses, which can contribute to air and water quality degradation (Figure 24) (Sound Ag, 2022).

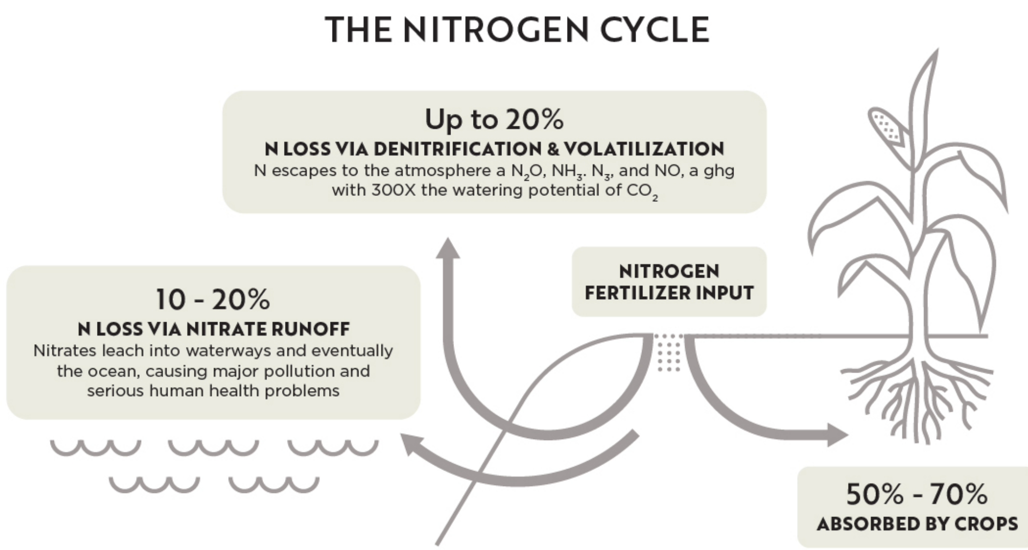

Figure 24: The Nitrogen Cycle (Sound Ag, 2022).

Fertilizer application rates can be lowered when used in tandem with practices such as no-till or strip-till, cover crops, and other agronomic practices, including improved nutrient recycling from manure and other waste streams. One farmer who grows crops along the Minnesota-Iowa border reported lowering his synthetic fertilizer use by 30 percent with these practices (Paulson, Schnitkey, Monaco, & Zulauf, 2025). While these techniques need to be tailored to the specific climate, soil chemistry, and intended crops, they are increasingly of interest as fertilizer efficiency is also a pressing economic objective.

The Minnesota Nutrient Reduction Strategy Report (Minnesota Pollution Control Agency, 2025) and Nitrogen Fertilizer Management Plan (Minnesota Department of Agriculture, 2026) aim to provide best management practices for cropland to increase fertilizer use efficiency and protect groundwater sources from nitrate contamination. The Iowa Nitrogen Initiative is currently recruiting farmers to enroll in a public-private partnership to better understand nitrogen use on a farm-by-farm basis, enabling recommendations for targeted, large-scale nitrogen reductionstobe implemented (Iowa State University Department of Agronomy, 2022). As of early 2026, the initiative has scaled materially: the partnership released N-FACT (Nitrogen Fertilization Application Consultation Tool) at the February 2025 Iowa Ag Expo — an APSIM-driven online decision-support tool that recommends custom nitrogen application rates by location, weather, soil nitrogen, planting date, cropping system, and market price — and the ISU team expanded from roughly 30 on-farm nitrogen-rate trials in 2024 to more than 500 in 2025, with enrollment open for the 2026 season and endorsement from the Iowa Department of Agriculture and Land Stewardship (Iowa State University News Service, 2025; IDALS, 2025; Iowa Nitrogen Initiative, 2026).

Lastly, while the GHG reduction benefits of switching from gray to green ammonia are clear at a macro scale, better tools are necessary to quantify and eventually monetize those benefits when farmers adopt low-carbon intensity or regenerative practices, which may include the use of low or no-carbon fertilizers. Unlike an ethanol plant, which can incorporate the carbon reduction from low-carbon fertilizer in its overall ethanol carbon intensity (CI) score and monetize it, the definition of similar economic incentives at the farm level is still uncertain. Ultimately, the decarbonization of the fertilizer supply chain will require more than just a one-to-one replacement of a specific synthetic fertilizer with a low orno-carbon drop-in replacement.

The Role of Policy, Incentives, Structures, and New Markets for Low CI Fertilizer Production in Minnesota

Shifting to a decentralized, locally produced AA will require significant capital investments. Therefore, it is important to consider the policies and programs recently put in place to support low-carbon-intensity processes and products.

Hydrogen tax incentives, such as those in the 2022 IRA, can bring green hydrogen — and thus green ammonia — to price parity with conventional products. However, after executive orders in January 2025 to pause the disbursement of IRA funds, and with the 2025 One Big Beautiful Bill (OBBB), some of these ten-year credits may be shortened or eliminated, leaving a gap in policy infrastructure to support the domestic expansion of green hydrogen and ammonia production.

The 2021 Bipartisan Infrastructure Law also created DOE's Regional Clean Hydrogen Hubs (H2Hubs) program, an $8 billion effort to establish regional hydrogen ecosystems. Among the selected hubs was the Heartland Hydrogen Hub (HH2H), which DOE explicitly positioned to support low-carbon nitrogen fertilizer production in the Upper Midwest. As of early 2026, HH2H has not been formally canceled but has materially stalled, driven largely by continued uncertainty around federal contracting and the broader clean-hydrogen policy environment, including 45V-related investment risk.

Beyond fertilizer, heavy industrial sectors such as chemicals, refining, cement, and steel — where fossil fuel use cannot be eliminated, but carbon emissions may be drastically reduced — represent another critical pathway for green ammonia as a hydrogen carrier or fuel and are essential to ensuring locally sourced green ammonia markets are not solely dependent on direct fertilizer application. (Figure 25). These policy developments and their implications are discussed in detail in APPENDIX 3: Incentives and Policies for Green Hydrogen and Ammonia.

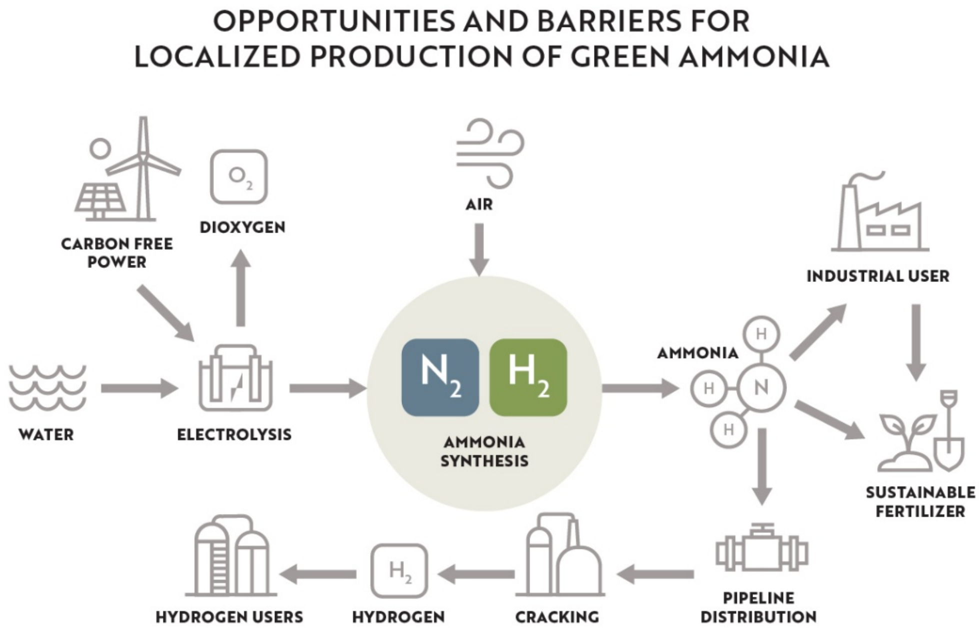

Figure 25: Opportunities and barriers for localized production of green ammonia

Recommendations

1. Green ammonia is technically feasible, but its economics are constrained by high capital intensity. For the foreseeable future, many projects will require some form of production support. In the U.S., the Inflation Reduction Act (IRA) provides an important incentive framework, but the timing, compliance requirements, and qualification constraints associated with the Section 45V hydrogen production tax credit mean that many projects cannot rely on 45V alone, and some will never be ready on time to benefit from the statute.

Developers should therefore evaluate complementary mechanisms that reduce upfront capital burden (for example, investment tax credits, grants, loan guarantees, and accelerated depreciation) as well as mechanisms that monetize low-carbon attributes at the product level (for example, premiums through offtake contracts, procurement programs, or credit markets where applicable). There is also substantial room for state-level policy to supplement federal support and, in some cases, close residual economic gaps. Over time, continued scale-up of electrolyzer manufacturing should reduce the cost of the critical equipment train, similar to the historical cost declines observed in wind and solar hardware. However, the market today still exhibits a first-mover disadvantage: early projects face higher equipment pricing, integration and execution risk, conservative financing, and uncertain "revenue stacking," all of which can keep otherwise viable concepts from progressing beyond development.

Finally, cost and performance improvements are not guaranteed. Continued research and development of lower-cost electrolyzer technologies (for example, anion exchange membrane, AEM, and solid oxide electrolysis cell, SOEC) and alternatives to the conventional Haber-Bosch synthesis loop remain, because these pathways could deliver step-changes in capital intensity, operating flexibility, and overall system efficiency. However, these R&D efforts need to happen in parallel with the industry build-up and are not a substitute for appropriate policies.

2. We recommend a follow-up study evaluating the site-specific feasibility of integrating green ammonia production with local renewable generation, including the potential to utilize curtailed power. Access to curtailed power makes siting of the production asset a critical consideration. The advantages of this approach are multifaceted: curtailed power may improve electrolyzer utilization while reducing overall power cost, as blocks of inexpensive power would supplement volumes purchased via PPA. Additionally, the introduction of flexible industrial load to a transmission corridor experiencing frequent curtailment can benefit grid stability through demand-side response and support local tax revenues that would otherwise decline during curtailment events. These benefits — which extend beyond the direct economic and environmental case for green ammonia — should be quantified as part of the analysis.

3. Tools and methods are needed to quantify, at the farm level, how fertilizer choices – and agronomics practices in general – affect the carbon intensity of an individual farming operation and a crop. Better measurement and attribution would enable more credible incentives for green ammonia and other low-carbon fertilizers by creating a defensible basis to monetize environmental attributes (for example, through premiums, contracts, or crediting mechanisms). Today, there is a lack of confidence in accurate measurements: existing carbon intensity estimates often rely on generalized emission factors, uncertain parameters, and incomplete data, which is often not sufficient for financial instruments that require auditability, reproducibility, and low uncertainty. The priority is therefore to develop measurement and accounting approaches that reduce uncertainty to a level consistent with credible verification and with the risk tolerance of buyers, insurers, and financiers.

4. While the overall ammonia market is growing, most of that growth is concentrated in large-scale production serving mainstream fertilizer supply chains. Retail demand for ammonia, while still significant, has been declining as urea becomes a more common nitrogen source. Urea has lower nitrogen content than anhydrous ammonia (AA) and, on a nitrogen-

equivalent basis, is often slightly more expensive, but it is substantially easier to handle and is generally subject to fewer safety and regulatory constraints.

Small-scale ammonia production, therefore, needs to win in local markets where AA can remain a meaningful part of the retail nitrogen mix. That requires two things: (1) targeted incentives and policies that explicitly favor locally produced ammonia (for example, demand-side credits, procurement preferences, local supply programs, and monetization of environmental benefits), and (2) delivered AA that is price-competitive, ideally supported by direct participation of farmers and other local stakeholders in the project.

Without a credible local market structure and a clear cost position, attracting investment may be difficult. Urea, produced from ammonia and carbon dioxide (CO_2), is a downstream product to consider, especially in Minnesota, where it is the primary nitrogen product utilized during the growing season and for side-dressing applications. Ethanol plants produce large volumes of relatively pure, concentrated biogenic CO_2; combining that CO_2 with green ammonia could enable low-carbon ("green") urea. This is consistent with how conventional urea is made today: natural-gas-based ammonia complexes capture process CO_2 from the hydrogen synthesis and react it with ammonia to synthesize urea. For green urea, the CO_2 feedstock must itself be carbon-neutral, because the CO_2 incorporated into urea is ultimately released back to the atmosphere after application and degradation in soils. Ethanol plants are among the largest domestic sources of biogenic CO_2, which is produced in concentrated and fairly pure streams, making them logical sites for urea integration.

The economics require further study because urea synthesis is more complex and generally less amenable to downscaling than ammonia; a viable concept would likely require a larger unit tightly integrated with an ethanol plant (or a hub aggregating multiple sources). This option may become more attractive if regional CO_2 aggregation, including pipeline networks, improves utilization at an acceptable cost and if available federal and state incentives for CO_2 capture and utilization can be monetized where eligible. New policies and marketing arrangements need to be explored to ease market volatility and its impact on farming communities and the ag commodity market, among them:

a. Anhydrous ammonia consumption is sharply seasonal, with applications concentrated in narrow fall and spring windows. A green ammonia facility must run as close to baseload as renewable supply allows in order to amortize a capital-intensive electrolyzer-and-synthesis train. The unavoidable consequence is that local turnover ratios are high and storage requirements are large — both in absolute terms and as a share of the project balance sheet. Permitted, code-compliant large-scale ammonia storage is also expensive to build, slow and politically sensitive to permit, and operationally demanding to maintain (safety, monitoring, hazardous-materials regulation, insurance).

The working capital tied up in pre-season inventory compounds the burden: at recent retail prices, even a modest share of seasonal demand represents tens of millions of dollars locked in tanks for several months each year. It is therefore unrealistic to expect that developers, cooperatives, or distributors will absorb the full capital, workingcapital, and regulatory load on their own balance sheets, particularly during early project years when revenue is uncertain and lender appetite is conservative. The implication for policy is that storage needs its own targeted support — and that support need not be a cash subsidy. Market-security instruments (offtake guarantees, public participation in the strategic-reserve concept described in the next bullet, working-capital revolving facilities, expedited and standardized state-level permitting pathways for code-compliant ammonia storage, and shared-use storage hubs co-financed by public and cooperative partners) can unlock private capital just as effectively as direct funding. Treating storage as a public-good complement to local production — rather than as the developer's residual problem — is what makes the strategic-reserve and contracting recommendations that follow actually executable.

b. Analyze the potential for a public or public/private strategic fertilizer reserve designed to smooth out supply chain disruptions and ensure that baseline local fertilizer requirements are met under most circumstances, and price shocks are locally smoothed. A precedent for such a reserve exists, for example, in Switzerland, where compulsory stockholding is managed by Agricura Genossenschaft, a private cooperative society that oversees reserves held as additional inventory by producers, importers, and distributors. Agricura maintains a guarantee fund to protect members from losses incurred from holding reserve stocks, financed by contributions from domestic fertilizer sales.

c. Explore new fertilizer contracting structures that index green ammonia to renewable electricity prices. The goal is to create a practical decoupling mechanism and a clearer value proposition for green ammonia, as gray ammonia remains tied to more volatile gas markets. One approach is a long-term "power-indexed fertilizer" contract: the ammonia producer secures a long-term power purchase agreement (PPA) or other fixed-price renewable power arrangement, and the fertilizer selling price is set via a transparent formula tied to that electricity price This can reduce price volatility for buyers and sellers: the producer locks in a major cost which enables credible long-term fertilizer pricing, and the buyer gets reduced exposure to fertilizer market volatility. These contracts also directly support project finance providing offtake agreements with a defined pricing mechanism and duration. The obvious problem is perceived hedge risk, especially early on: farmers may fear being locked into an unfavorable contract if the fixed price of green ammonia and that of conventional ones diverge. To overcome that risk, publicly-backed risk backstops can be considered as a targeted incentive. These could be an insurance-style program, a contract-for-difference (CFD) structure with capped downside, or a limited-duration price collar funded by a public entity. The point is to underwrite early-market risk until confidence and standard contract terms develop.

d. Lastly, invest in and promote the use of recycled nutrients. Farmers have always relied on manure and will continue to do so, but there are opportunities to optimize how it is applied—raising its economic value while reducing its potential environmental harms. One key constraint is that manure use is often limited by a single excess nutrient, such as phosphorus. Capturing manure's full value will therefore require a combination of technical and economic solutions that make its use more efficient. There is a large potential amount of underutilized nutrients in a variety of organic waste, ranging from food waste to sewage sludge. These nutrients have been proven to be safely recoverable with appropriate use of existing technologies and assets. Recent studies (Porter & James, 2020) have shown that recycled nutrients could supply up to one-third of Minnesoota's nitrogen needs, while the demand for synthetic nitrogen indicates a substantially lower effective recycle rate.

In this work, we considered a 50,000 tpa plant to provide a realistic yet impactful percentage of the ammonia demand in the state of Minnesota. While the economies of scale from multiple smaller plants may not significantly change the LCOH, these could benefit from even tighter integration with the current retail and distribution system. Such analysis would not stop at the plant gate but would look at a roadmap for five-ten Minnesota cooperatives, including storage retrofits, safety training, inventory management, product segregation for "green" branding, with a simple payback table under various green premiums and retail prices. Under this scenario, it would be worth considering not just AA but also specialty blends and urea ammonium nitrate (UAN) — using conventional urea — to further improve margins by going deeper into the value chain.

In conclusion: Green ammonia production is technically feasible but faces significant economic barriers rooted in high capital intensity, first-mover disadvantage, and market uncertainty. Overcoming these barriers requires action along four mutually reinforcing lines:

- First, project investment must be derisked through a layered policy framework — combining federal production incentives such as the Section 45V tax credit with capital-side mechanisms (investment tax credits, grants, loan guarantees, accelerated depreciation) and complementary state-level support.

- Second, production should be tightly integrated with local renewable generation, particularly by siting facilities to absorb curtailed power, thereby improving electrolyzer utilization, lowering electricity costs, and supporting grid stability.
- Third, viable local markets must be deliberately created through targeted demand-side policies, new contracting structures such as power-indexed fertilizer pricing and publicly backed risk backstops, cooperative distribution and shared-use storage models, expedited permitting pathways, and workingcapital support for code-compliant ammonia storage, expanded recovery of recycled nutrients, and — where conditions allow — downstream integration into green urea at ethanol plants.
- Fourth, continued R&D in lower-cost electrolyzer technologies and alternative synthesis pathways must proceed in parallel, not as a substitute for near-term policy action.

Underpinning all four lines, robust farm-level measurement and certification tools are needed to credibly quantify carbon-intensity reductions and provide the defensible basis for monetizing environmental attributes through premiums, contracts, and credit markets.

APPENDIX 1: Proposed Expansions in Ammonia Production Since 2022 And Current Status of the Industry

By late 2024, 38 proposed projects were poised to increase annual U.S. ammonia capacity by over 60 million metric tons, nearly quadrupling current capacity from 21 to 81 million metric tons. However, the expansion has begun to falter following the passage of the One Big Beautiful Bill (OBBB) in July 2025, with five blue ammonia projects totaling 5.4 million metric tons canceled or put on hold, and many more green ammonia projects either canceled or put on hold. The Environmental Integrity Project's Oil & Gas Watch database (oilandgaswatch.org) and the Ammonia Energy Association (ammoniaenergy.org) are the two best sources for ongoing tracking. The Ohio River Valley Institute (ORVI) also publishes periodic reports on the status of proposed projects. This is a selected list of announced projects.

Blue/Low-Carbon Ammonia (Natural Gas + CCS)

- **CF Industries / Mitsui / JERA — Blue Point Complex, Ascension Parish, LA** (April 2025 JV announced). The facility is designed with ~1.4 million metric ton annual capacity, expected to capture >95% of CO_2, with construction beginning in 2026 and production expected in 2029. CF Industries had previously announced the Mitsui partnership in 2022 for a Gulf Coast blue ammonia facility.
- **OCI → Woodside Energy — Beaumont, TX** (ground broken 2022; acquired by Woodside in August 2024 for $2.35B). OCI built a 1.1 million metric ton plant at a cost of $1 billion, with Linde supplying hydrogen and ExxonMobil handling CO_2 transport and storage. Now renamed the Beaumont New Ammonia Project, construction of Train 1 is underway with operations readiness expected in the second half of 2025.
- **Wabash Valley Resources — West Terre Haute, IN** (announced ~2021; DOE conditional loan commitment Sept 2024). A $1.559 billion DOE loan toward a total $2.4 billion investment for 500,000 metric tons/year of low-carbon ammonia from industrial waste feedstock with CCS — potentially the first carbon-negative ammonia production process in the U.S.. The loan was finalized in late 2025.

- **LSB Industries / Lapis Carbon Solutions — El Dorado, AR** (development agreement signed 2022). CCS retrofit to LSB's existing ammonia plant, with the sequestration injection well drilled in April 2025 and CCS operations expected in late 2026.
- **Yara / Enbridge — Ingleside Energy Center, Corpus Christi, TX** (MoU announced March 2023). A blue ammonia export project leveraging existing terminal infrastructure, with feedstock from the Texas Eastern pipeline and CCS targeting 95% emission reduction.
- **Lake Charles Blue Ammonia — Calcasieu Parish, LA** (Mitsubishi Corp, Proman, Idemitsu Kosan). Proposed blue ammonia plant targeting 80% emissions capture; awaiting permit application as of recent tracking.
- **Air Products — Ascension Parish, LA.** A $4.5 billion blue hydrogen and ammonia production plant described as potentially the single largest instance of permanent CO_2 sequestration in the world.
- **Ten08 Energy (Navigator Holdings / Attis Clean Energy) — Gulf Coast, TX** (announced 2024). A hybrid blue/green ammonia facility targeting 1.4 million metric tons annually, starting in late 2029 or early 2030.
- **St. Charles Clean Fuels — St. Rose, St. Charles Parish, LA** (draft permit July 2024). Up to 8,000 metric tons/day from natural gas, backed by Copenhagen Infrastructure Partners and Sustainable Fuels Group, claiming up to 99% CO_2 capture.

Green Ammonia

- **CF Industries — Donaldsonville, LA** (announced 2021). A 20,000 ton/year green ammonia project using a thyssenkrupp electrolyzer — described at announcement as the largest of its kind in North America. Construction began in 2021.
- **First Ammonia — Victoria, TX** (Series B funding Sept 2024). A flagship green ammonia facility using Topsoe SOEC electrolyzers integrated with an ammonia loop, designed for fluctuating operation matched to renewable energy availability.
- **Synergen Green Energy** — Unspecified U.S. locations (announced 2023). A Houston-based company that selected Topsoe as technology licensor for green ammonia plants in the U.S..

- **Monolith** — Olive Creek, Hallam, NE (expansion). Uses methane pyrolysis to produce hydrogen (and carbon black byproduct), with a $1.04 billion DOE Title XVII loan securing expansion. This is a turquoise hydrogen pathway rather than strictly green.

The build-out demonstrated above was propelled by both increasing demand for ammonia and over $100 billion in tax subsidies for hydrogen production in the 2022 Inflation Reduction Act (IRA), along with enhanced tax credits for CCS. However, the 45V clean hydrogen production tax credit has become a central uncertainty. Following the OBBB's passage, companies now have a much shorter timeline: months to break ground on their proposed facilities to qualify for the 45V tax credit, and the nine ammonia and several announced projects were canceled. The law terminates the 45V Clean Hydrogen Production Credit for projects that commence construction after December 31, 2027, accelerating the previous phase-out date of 2033 (Bipartisan Policy Center, 2025). At the same time, the law did not impose material restrictions on the Section 45Q Carbon Oxide Sequestration Credit (Buchanan Ingersoll & Rooney, 2025), and actually provides parity in credit rates — $17/metric ton base credit, $85/metric ton if labor requirements are met — for all carbon capture processes, including sequestration, utilization, and enhanced oil recovery (RSM, 2025). So blue hydrogen/ammonia (CCS-based) got relatively favorable treatment, while green hydrogen projects face a much tighter construction deadline. The 45Q credits offer $60 to $180/ton of sequestered carbon, and the final version of the bill eliminated the previous distinction between uses of captured carbon, making all carbon capture projects eligible for the same incentives (Green Hydrogen Organization, 2025). As the 45V measure expires, green hydrogen projects will be pushed out of the market by missing word?, while subsidized blue hydrogen may increase the competitiveness of upgraded existing gray hydrogen assets (Ohio River Valley Institute, 2025).

APPENDIX 2: Using Curtailed VRE Power for Green Ammonia

This appendix describes how curtailed variable renewable energy (VRE) — primarily wind in the Upper Midwest—can be treated as a low-carbon electricity resource for power-to-ammonia (P2A) systems. The focus is on the MISO Midwest subregion and on transmission-constrained corridors in the Upper Midwest where congestion and curtailment are commonly observed. The intent is to complement the main report's green-ammonia discussion with a grid-aware perspective on curtailment drivers, market signals, and siting considerations. During periods of oversupply and congestion, curtailed energy may be available at low effective prices, potentially improving electrolysis economics even with reduced or no subsidies. In addition, flexible P2A loads can provide grid benefits—such as load shifting, ramping, and congestion relief—when properly designed and operated. This appendix is illustrative rather than definitive. Curtailment is both time- and location-dependent; capturing it typically requires siting near the constrained node (or co-locating behind the same point of interconnection). Project-specific feasibility, therefore, requires nodal (or substation-level) analysis using market data, transmission constraints, and interconnection information. This type of analysis exceeds the scope of this project; our hope is to draw attention to this opportunity, which merits detailed investigation as an independently funded follow-on project.

Curtailment as usable electricity resource

Curtailment occurs when electricity generation is deliberately reduced to below available output. In VRE-heavy regions, curtailment is often driven by:

- oversupply (generation exceeding load) and/or
- congestion (insufficient transmission transfer capability to deliver power from the generating area to the load).

The U.S. Energy Information Administration (EIA) notes that in the U.S. Midwest, wind curtailments have grown materially since 2019, reflecting both wind build-out and transmission constraints (U.S. Energy Information Administration, 2024).

From a P2A perspective, curtailed energy can be viewed as a “non-firm” electricity supply that is available in specific hours at specific locations. Capturing it typically requires one (or a combination) of the following approaches:

– Locational siting: place electrolyzers near the constrained generation pocket so the load can consume energy that would otherwise be curtailed.
– Commercial arrangement: contract with renewable generators (or utilities) for a curtailed energy block or take advantage of low/negative price periods when available.
– Dynamic operation: operate electrolyzers dynamically (fast ramping, turndown, start/stop) and use hydrogen and/or ammonia storage to buffer intermittency.

Electrolyzers are technically capable of rapid load changes. National Laboratory of the Rockies (formerly known as National Renewable Energy Laboratory, NREL) testing and literature surveys show electrolyzer systems can respond on very short time scales (sub-second response for setpoint changes in some tests) and start/stop in minutes, supporting their role as a flexible load that can follow VRE availability and market signals (National Laboratory of the Rockies, 2014). While ammonia synthesis is unlikely to match the dynamic response of an electrolyzer—meaning hydrogen storage cannot be eliminated—a flexible ammonia loop with some turndown capacity will still be advantageous for reducing process costs.

MISO: scale and drivers of VRE curtailment

EIA reports that average hourly wind curtailment in MISO rose from 242 MW in 2019 to 508 MW in 2023; the market monitor attributed a substantial portion of 2022 congestion to high wind output, with average hourly wind curtailments of 726 MW in 2022 and hourly curtailments reaching as high as 5.9 GW in some hours (U.S. Energy Information Administration, 2024). Utility filings in the Upper Midwest show the same basic pattern at a more local scale. In Northern States Power Company’s Minnesota electric-operations true-up reporting (covering a multi-state area that includes Minnesota, North Dakota, South Dakota, Iowa, and Wisconsin), 2023 wind curtailment for the company’s wind projects totaled 1,107,395 MWh, with most categorized as economic curtailment (1,054,805 MWh) and a smaller portion as transmission-related (52,590 MWh) (Northern States Power Company, 2023). In that same filing, curtailment is linked to MISO's real-time dispatch process: MISO's security-constrained economic dispatch (SCED) runs frequently (every five minutes in the cited description) and sends dispatch targets to dispatchable intermittent resources; when locational marginal prices fall below an offer price, wind may be dispatched down, and binding transmission constraints and outages also drive curtailment.

Upper Midwest corridors relevant to curtailment capture

Curtailment is strongly associated with transmission-limited export capability from high-VRE areas. MISO's Long Range Transmission Planning (LRTP) process explicitly addresses future reliability and transfer needs under evolving resource portfolios. Tranche 1 (approved 2022) consists of 18 projects, and Tranche 2.1 (approved December 2024) adds a 24-project portfolio in the MISO Midwest subregion that includes a 3,631-mile 765 kV and 345 kV backbone targeted for 2032–2034 in-service dates (MISO, 2026) (MISO, 2022). Within Tranche 1, MISO describes several "sections" with distinct regional benefits, including:

- addressing thermal and voltage issues for Western Minnesota and the Eastern Dakotas;
- relieving constraints in the Twin Cities load center driven by high renewable flows and reinforcing the outlet toward Wisconsin load centers; and
- providing an additional 345 kV path southeast across Iowa, linking high-renewable regions in the west to the Quad Cities load center and broader MISO outlets.

These descriptions align with the types of corridors where curtailed-energy capture strategies are most plausible: areas where VRE is concentrated, where congestion is persistent, and where large transmission projects are planned to increase transfer capability.

Example corridor groupings and representative LRTP projects

This example provides an illustrative grouping of Upper Midwest corridors and representative LRTP project segments (from Tranche 1 and Tranche 2.1 project naming) that are relevant when screening for P2A siting opportunities. The intent is not to define exact siting, but to show how corridor-thinking can link curtailment risk, transmission constraints, and future system evolution LRTP segment names in Table 11 are drawn from MISO Tranche 1 and

Tranche 2.1 project lists and dashboards; corridor descriptions summarize the benefit statements in the Tranche 1 report and should be validated with nodal studies for any specific project.

Table 11: LRTP segment names are drawn from MISO Tranche 1 and Tranche 2.1 project lists and dashboards; corridor descriptions summarize the benefit statements in the Tranche 1 report and should be validated with nodal studies for any specific project (MISO, 2022), (MISO, 2025).

Illustrative corridor (Upper Midwest focus)	*Representative LRTP segments (examples)*	*Grid issue signal (examples)*	*Why it matters for curtailed-energy P2A*
Eastern Dakotas ↔ Western Minnesota	Jamestown–Ellendale; Big Stone South–Alexandria; Big Stone South–Brookings County–Lakefield Junction; Bison–Alexandria	Thermal/voltage limits and export constraints from high wind areas; recurrent binding constraints listed for MN/ND/SD in utility curtailment reporting	Co-located or nearby flexible load can consume energy during congestion events, reducing dispatch-down and monetizing otherwise lost output
Minnesota (southern) ↔ Wisconsin outlet	Wilmarth–North Rochester–Tremval; Tremval–Eau Claire–Jump River; North Rochester–Columbia; Iron Range–Arrowhead	Constraints associated with high renewable flows toward/past the Twin Cities and toward Wisconsin load centers	P2A near major substations/outlets can access both VRE supply and improved deliverability as transmission expands
Iowa west ↔ Iowa east / broader MISO outlets	Webster–Franklin–Marshalltown–Morgan Valley; East Adair–Marshalltown–Sub T (Tranche 2.1); Sub T–Woodford County–Collins & Reynolds	Congestion and limited transfer capability along eastbound paths during high wind/low load periods	Creates candidate nodes for flexible industrial loads that can respond to price/curtailment signals and support system balance

Converting curtailed energy into potential green ammonia output

To translate curtailed electricity into an order-of-magnitude green-ammonia potential, a simple conversion can be used:

Potential NH3 (t/y) ≈ Captured curtailed energy (MWh/y)/ Specific electricity consumption (MWh/t-NH3)

The specific electricity consumption depends on electrolyzer efficiency, air separation, compression, and Haber–Bosch synthesis integration. A representative range for "current best available" fully electrified green-ammonia systems is often cited on the order of 10–12 MWh per metric ton of NH3 (including electrolysis). Using EIA's MISO-wide average hourly wind curtailment values as a rough proxy for annual curtailed energy, a theoretical green ammonia production from MISO NW corridor curtailed power was estimated (Table 12).

Table 12: Theoretical green ammonia production from MISO NW corridor curtailed power.

Curtailment Amount	*Implied curtailed energy*	*NH3 @ 10 MWh/t*	*NH3 @ 12 MWh/t*
MISO wind curtailment (avg hourly), 2023 (508 MW average curtailed)	4.45 TWh/y (4,450,080 MWh/y)	445,008 t/y	370,840 t/y
MISO wind curtailment (avg hourly), 2022 (726 MW average curtailed)	6.36 TWh/y (6,359,760 MWh/y)	635,976 t/y	529,980 t/y

The values in Table 12 represent a theoretical upper-bound, system-average translation from aggregated curtailment to commodity production. In practice, only a fraction of curtailed energy at the system level is "capturable" by any one project because curtailment is spatially concentrated and occurs in clusters of hours. The maximum hourly curtailment (e.g., 5.9 GW cited for 2022) indicates that capturing all curtailment would require very large electrolyzer capacity that would be idle many hours; most projects will rationally target partial capture and use other power supply strategies for the balance.

Practical project design implications

A curtailed-energy strategy influences both siting and plant design. Key implications include: Siting must be "curtailment-aware": A load that is electrically too distant from the constrained pocket typically cannot access the curtailed energy because the constraint is what prevents delivery.

- Hybrid power procurement: Projects often may capture curtailed energy along with firmed renewable PPAs, market purchases, and/or storage to achieve a target ammonia capacity factor.
- Flexibility architecture: Decouple variable electricity input from the ammonia loop using hydrogen storage (and/or intermediate chemical storage) so the synthesis section can operate more steadily when desired.
- Grid value: Beyond energy arbitrage, flexible electrolyzers may provide demand response or ancillary services when market rules permit; fast-response capability has been documented for electrolyzer systems.

In MISO specifically, co-location of new industrial loads with renewable generation behind a shared point of interconnection is an active planning/market topic. MISO identified that developers of large loads (including green hydrogen) increasingly seek co-location on the low-voltage side of collector substations, noting that current processes treat load registration and generation interconnection separately (MISO, 2026). Resolving these planning and registration questions can materially affect the most direct route to consuming energy that would otherwise be curtailed.

Data needs for a corridor-level screening analysis

To move from an illustrative example to a quantitatively robust corridor screening and siting recommendation, inclusive of a detailed techno-economic analysis, a next-phase analysis would typically include:

- **Curtailment time series by location:** Resource-level curtailment/dispatch-down instructions, nodal price patterns (LMP and congestion/loss components, as available), and transmission constraint “binding hours” (e.g., real-time binding constraints and shadow prices).
- **Transmission topology and upgrade timelines:** Existing 115/230/345 kV constraints and congestion drivers; planned upgrades (e.g., LRTP/MVP facilities); state and local siting status; and expected in-service dates.
- **Interconnection pathways:** Candidate substations/points of interconnection (POIs), interconnection queue status, and a comparison of behind-the-meter/co-located configurations versus standalone load interconnection.
- **Water, permitting, and community screening:** Water availability and rights, zoning and land-use constraints, environmental permitting requirements, and community considerations for industrial development.
- **Commercial strategy and offtake:** Prospective ammonia buyers, transportation and logistics options, and contracting structures—both for electricity supply (e.g., PPAs or structured procurement) and for commercial products (ammonia/hydrogen).
- **Operational integration and storage sizing:** A co-optimized strategy combining curtailed energy with firming mechanisms (e.g., PPAs, shaped products, or storage) to manage variability; integrated modeling of electrolyzer flexibility, ammonia-loop ramp-up/turn-down limits, and the resulting hydrogen storage requirements.
- **Policy and incentives sensitivity:** The impact of tax credits and other incentives on project configuration, contracting strategy, and delivered cost of ammonia.

The analysis in this appendix suggests that curtailed VRE in the Upper Midwest, particularly within transmission-constrained MISO corridors, can represent a meaningful, low-carbon electricity resource for green ammonia production when paired with appropriately flexible P2A designs and siting strategies. While the discussion here is intentionally illustrative and does not substitute for nodal, project-specific feasibility work, the persistence of congestion-driven curtailment and the prospect of accessing low-priced energy **during** binding events indicate that curtailment capture could materially improve electrolysis economics and provide system benefits through flexible load operation. Taken together, these factors justify a more detailed, quantitative next-phase investigation into screen corridors, evaluate interconnection pathways, and develop an integrated commercial and operational strategy that links curtailed energy availability with PPA structures, electrolyzer dispatch, ammonia-loop dynamics, and storage requirements.

APPENDIX 3: Incentives and Policies for Green Hydrogen and Ammonia

Expanding production of green hydrogen and derived products was one of the stated aims of the IRA of 2022, which mandated the establishment of incentives, in the form of tax credits, for qualifying clean hydrogen production facilities. Section 45V of the Internal Revenue Code establishes a production tax credit for "qualified clean hydrogen" produced in the United States, with the credit amount determined by the hydrogen's lifecycle greenhouse gas emissions rate (well-to-gate) expressed in kg CO2e per kg H2 and calculated using the 45VH2-GREET (greenhouse gases, regulated emissions, and energy use in technologies) model (or a provisional emissions rate pathway when a production pathway is not represented), the statutory credit tiers apply where lifecycle emissions are at or below 4.0 kg CO2e/kg H2, with higher applicable percentages and thus higher credits for lower emissions bands, including the top tier for hydrogen below 0.45 kg CO2e/kg H2. At the top tier, credits can reach $3/kg of H2, creating a powerful incentive that can qualify green hydrogen competitively with gray hydrogen despite current high capital costs. Part of the rationale behind the program is to enable the scale-up of electrolytic hydrogen production, thus enabling the expected reduction in cost of electrolyzers as production volumes increase. In practice, there are limitations to the applicability of 45V that need to be understood, in the context of using curtailed power from VRE assets. Curtailment is not a compliance category under 45V. Curtailment describes a grid condition (congestion, oversupply, negative pricing, reliability dispatch) and does not, by itself, make electricity "clean" for lifecycle accounting. In principle, under specific conditions, non-renewable power may be curtailed. It just happens that the variable and non-dispatchable nature of variable renewable electricity (VRE) makes curtailment a particularly common management tool.

Eligibility criteria for 45V

Eligibility for 45V depends on the lifecycle greenhouse gas emissions intensity (kg CO2e per kg H2) calculated under 45V's required methodology. For electrolytic hydrogen, "curtailment-driven economics" can coexist with 45V eligibility only the electricity used for electrolysis can be substantiated as low-emissions electricity in the lifecycle accounting. In practice, that generally requires qualifying Energy Attribute Certificates (EACs) meeting the three qualifying "pillars" of incrementality, temporal matching, and deliverability plus proper accounting of retirement recorded in a qualified registry and verifiable by an independent verifier to prevent double booking. A few key terms and appear in the rules:

- "*Additionality*" is the common policy term. The 45V electricity attribute rule uses "*incrementality*" as the operative requirement for electricity EACs.
- "*Deliverability*" and "*temporal matching*" are explicitly defined requirements for qualifying EACs used to claim electricity from a specific generator rather than defaulting to regional grid electricity.
- "*Proper retirement*" is mandatory when using EACs: acquisition and retirement must be recorded in a qualified energy attribute certificate (EAC) registry/accounting system and must support verification and prevent double counting.

Additionality (Incrementality)

Incrementality is satisfied when the electricity generating facility's commercial operations date (COD) is no more than 36 months before the hydrogen production facility for which the EAC is retired was placed in service. The intent of the rule is designed to reduce the risk that electrolyzer load is "backfilled" by fossil generation on the grid while papering over it with attributes from older clean assets.

Examples:

- Qualifying: A wind farm reaches COD in 2026; an electrolyzer is placed in service in 2027. EACs from that wind farm can satisfy incrementality for that electrolyzer.
- Non-qualifying: A 2012 wind fleet experiences frequent curtailment and negative prices. An electrolyzer placed in service in 2027 attempts to use cheap power from that 2012 fleet. The COD is far outside the 36-month window, so incrementality, thus 45Velegibility fails.
- If an old wind farm is uprated, only the prorated "uprated production" can be treated as incremental under the rules; the pre-uprate output remains non-incremental.

Deliverability

Deliverability is satisfied when the electricity-generating source and the hydrogen production facility are located in the same 45V "region," determined by the balancing authority to which each facility is electrically interconnected, as specified in the table included in the regulations. The rule is intended to ensure the claimed clean generation can be reasonably delivered and affect the marginal emissions of the electrolyzer's power consumption. Curtailment strategies are highly location dependent. Lack of deliverability would defeat the whole purpose of accessing curtailed power, hence curtailed power would satisfy this requirement.

Examples:

- Qualifying (typical case): A solar facility and the electrolyzer are both interconnected to balancing authorities listed in the same 45V region. EACs from that solar facility can satisfy deliverability.
- Non-qualifying (common): An electrolyzer in a balancing authority region attempts to use EACs from a generator interconnected to a balancing authority assigned to a different 45V region. Deliverability will, in general, fail unless an explicit allowance for a verifiable "cross-region delivery" pathway is granted.

Temporal matching

Temporal matching is satisfied when the electricity represented by the EAC is generated in the same hour that the hydrogen production facility uses electricity to produce hydrogen. Treasury indicates a transition that allows annual matching initially, with hourly matching required starting in 2030. Temporal matching is intended to prevent a scenario where clean electricity generated, say, at noon is used to claim clean hydrogen produced at 2 a.m., when marginal grid power may be fossil-heavy. Curtailment strategies are time-dependent, so temporal matching would be satisfied. It should be noted that the rule allows for power storage and later discharge. The rules contemplate temporal matching based on discharge hour – when the registry can track where the power was generated, the storage use, and account for losses and whether the storage is located in the same region as the generator and hydrogen facility.

Examples:

- Qualifying (hourly match): The electrolyzer runs, for example, between 02:00AM and03:00AM. The retired EACs correspond to MWh generated during the same time frame, and all other requirements are met.
- Potentially qualifying pre-2030: The electrolyzer operates primarily in curtailment hours; annual EAC matching is used during the transition period. This can be compliant during the transition, but it creates exposure to the 2030 hourly matching regime unless contracts and registries support interval attributes.

Proper retirement and exclusivity

This is a relatively uncontroversial part of the regulation that defines an EAC as a tradeable instrument issued through a qualified registry or accounting system. The EAC can be retired by or on behalf of its owner or the party with the right to claim the attributes. When using qualifying EACs for 45V, the acquisition and retirement must be recorded in a qualified EAC registry/accounting system so that it can be verified by a qualified verifier. This ensures that the EAC is not reused.

Implications for the use of curtailed power

Curtailment improves the electricity price profile at particular nodes/zones, often producing low or negative locational marginal prices (LMPs). Under the rule, that economic signal does not establish low lifecycle emissions for 45V. The lifecycle emissions treatment turns on whether the electricity can be attributed to qualifying clean generation via qualifying EACs. It should be noted that the rule, alternatively, allows a user to claim the credits without qualifying EAC if default grid emissions inputs still yield a qualifying lifecycle emissions tier. Currently, this is highly unlikely in most of the U.S.. A curtailment-driven operating strategy is compatible with 45V when the electricity claims for 45V are supported by EACs that satisfy incrementality. The EACs satisfy deliverability by being in the same 45V region through a balancing authority interconnection, or a verifiable cross-region delivery pathway.
Temporal matching is satisfied hourly in the long run, with annual matching after 2030.

The EACs are retired properly in a qualified registry with exclusivity and verification. Of these conditions, all are generally satisfiable, but for the incrementality one, as much of the curtailed power comes from a legacy generation fleet whose COD is older than 36 months.

The incrementality rule can reasonably be described as a material impediment to near-term electrolytic hydrogen deployment where the business model depends on monetizing legacy curtailment or existing wind or solar fleets, because much of those fleets often fall outside the 36-month lookback that governs whether an Energy Attribute Certificate (EAC) can be treated as “incremental.” The final rules explicitly retain the qualifying EAC framework despite extensive criticism that it raises costs and slows or pre-empts projects. In that narrow but important sense, incrementality is a major obstacle to use older VRE, especially curtailed VRE as the backbone of a low-cost green hydrogen strategy, because it forces either (i) new-build clean supply (or other limited qualifying pathways) or (ii) acceptance of grid-based emissions assumptions that often miss the qualifying credit tiers. Conceptually, other mechanisms could target the same induced-emissions concern while allowing crediting of older VRE, but they trade simplicity of definition for some verification complexity. During rule making, the discussion focused on proxy approach such as deeming a small share of hourly output from pre-2023 minimal-emitting generators as satisfying incrementality while still requiring temporal matching and deliverability. The final rules, however, largely declined broad carveouts or exemptions including rejecting calls to exempt behind-the-meter arrangements. Instead the rules maintain the qualifying EAC framework, arguing that exemptions or delays would lead to induced emissions, while only shifting some timelines and adding limited flexibilities inside the framework – for example, delaying hourly temporal matching until 2030.

General consideration on incentives for green hydrogen and green ammonia

Given that near-term changes in Federal policy should not be assumed, there is a coherent argument for State policy to focus on reducing capital risk rather than open-ended per-kilogram production credits. Production credits can be politically framed as an uncapped liability and are difficult to budget ex ante, whereas investment-focused tools can be capped, appropriated, and targeted to derisk first-of-a-kind (FOAK) deployments. SuchState incentives do not require to “pick a hydrogen price”. Rather, they would focus on instruments such as capital grants or rebates per installed kilowatt, investment tax credits at the State level, sales and property tax abatements, industrial bonds, interest-rate buydowns, State-backed loan guarantees or credit enhancements. They could also be tied to milestone-based goals that only pay upon commissioning or verified performance. More sophisticated variants can target risk rather than cost, e.g, partial guarantees on offtake contracts, floor-price mechanisms for ammonia, or insurance backstops for interconnection and market volatility during initial years. Ultimately, the goal is the same. As the constraint is capital intensity and first-mover risk and not just electricity cost, then policy that lowers the weighted average cost of capital, absorbs discrete early-stage risks, and accelerates industry scale-up can unlock the opportunity without creating an indefinite production subsidy obligation.

APPENDIX 4: TalusAg Green Ammonia Demonstration Plant — Boone, Iowa

TalusAg (formerly Talus Renewables), an energy technology company founded in 2021, partnered with Landus Cooperative to build and operate what they describe as North America's first commercial-scale green ammonia production facility at the Landus Fertilizer Facility in Boone, Iowa (TalusAg, 2025; Landus Cooperative, 2024). The Boone plant is a demonstration-scale system housed in a modular, containerized format with 1.4 MW electrolyzer feeding a conventional Haber-Bosch loop. The Boone demonstration system is powered by solar energy. Ideal Energy designed a solar array for the facility, and the system integrates with existing grain drying infrastructure at the Landus site. The project optimizes power consumption by running the electrolyzer between grain drying demand spikes, which typically account for 60% of facility energy costs — a "valley filling" approach that avoids additional demand charges (TalusAg, 2025; Munasinghe & Krimer, 2024). The unit rated at approximately 1 metric ton of ammonia per day, with an annualized capacity of roughly 365 tons. It consists of five core system modules, with the hydrogen generation unit and ammonia synthesis unit being the primary containers. The demonstration plant has been operational since February 2025. The Boone site includes a new $15 million, 75,000-square-foot fertilizer manufacturing and repackaging facility, with a ribbon-cutting held in mid-June 2024 (Landus Cooperative, 2024). USDA provided a $4.9 million grant to support the project under the Rural Energy for America Program (USDA Rural Development, 2024). Planting began the week of April 14, 2025, making it the first corn crop in the U.S. grown with American-made green ammonia (Landus Cooperative, 2025). Landus collected agronomic data throughout the 2025 growing season, comparing performance of the green ammonia against control strips using conventional AA. TalusAg claims their green ammonia can be 20% to 30% cheaper than commodity ammonia, enabled in part by the Clean Hydrogen Production Tax Credit (45V), which provides up to $3.00/kg of clean hydrogen produced over a ten-year incentive period (TalusAg, 2025; U.S. Department of the Treasury & IRS, 2025). The company also claims its technology can lower a farmer's carbon intensity score by about 25%. The Boone demo is intended as a proving ground for TalusAg's larger commercial system, the talusTen, which is rated at 20 tons per day (~7,000 tons/year) (TalusAg, 2025). A larger facility in Eagle Grove, Iowa, along with another in Manning, are in development, with Eagle Grove expected to come online in late 2025 (Landus Cooperative, 2025). As of 2025 TalusAg plans to deploy another 12 sites in Iowa for Landus, with 78 total potential sites being evaluated across the Corn Belt over the next three to five years (TalusAg, 2025).

APPENDIX 5: Ammonia and Urea—Chemistry, Logistics, Agronomy, and environmental implications.

Earlier, we saw that while ammonia remains the cornerstone of the synthetic fertilizer industry, at the retail level, urea is increasingly preferred to ammonia. Economically, urea appears cheaper or equivalent on a per-ton basis (Figure 26), but if we compare the two products in terms of nitrogen price, urea is generally somewhat more expensive (Figure 27), as expected, given the additional processing needed to make urea from ammonia.

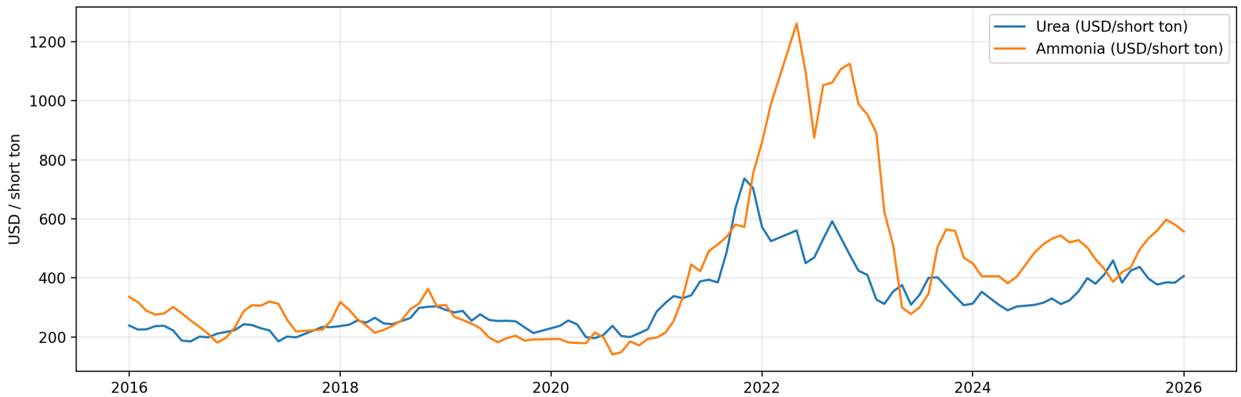

Figure 26: Urea and Ammonia prices, U.S. Gulf Coast (Source Intratec).

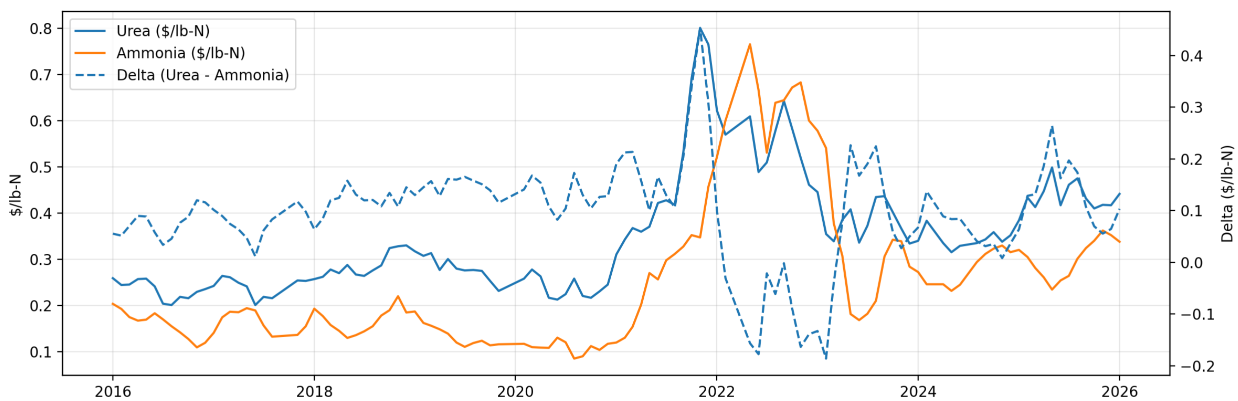

Figure 27 Price of N in ammonia and urea and their spread.

Urea is established as the primary nitrogen fertilizer despite this apparent disadvantage. This appendix clarifies the distinction between ammonia and urea as industrial products and fertilizer, explaining why urea has, over time, become a more common source of nitrogen. We also address the role of carbon dioxide in urea to clarify a common source of confusion.

Ammonia: a carbon-free nitrogen carrier

Ammonia (NH_3) is a simple inorganic molecule consisting only of nitrogen and hydrogen. Because ammonia contains no carbon, its use does not entail any direct emission. Any climate or carbon-intensity discussion about ammonia, therefore, depends on upstream production choice, namely, hydrogen source and process energy.

Industrial ammonia is produced primarily through the Haber–Bosch synthesis reaction:

$$N_2 + 3H_2 \rightarrow 2NH_3$$

The synthesis loop does not inherently generate CO_2. In conventional plants, however, the hydrogen feed is often produced from fossil sources, such as natural gas, through a process called reforming, which generates concentrated CO_2. So when one refers to the carbon intensity of ammonia, the reference is primarily to these emissions, ammonia being otherwise intrinsically carbon-free (IPCC, 2006).

From a physical-handling perspective, anhydrous ammonia is typically stored and transported as a pressurized liquid or, for large scale storage, refrigerated liquid. The hazards of ammonia are not irrelevant; anhydrous ammonia systems are governed by strict design and operating standards, and agricultural distribution commonly relies on dedicated tanks and specialized application equipment. Ammonia tanks with capacity above 2000 gallons are subject to environmental permitting (OSHA, n.d.).

Urea: a carbon-containing nitrogen carrier

Urea ($CO(NH_2)_2$) is fundamentally different. It is carbon-containing: each molecule includes one carbon atom and one oxygen atom (a carbonyl group) bonded to two amine groups. Urea is commonly manufactured and distributed as a solid (prills or granules) and is compatible with standard, non-specialized dry-bulk logistics and on-farm storage practices.

A practical way to summarize the product difference, which includes farm use, is:

- Ammonia: carbon-free, typically handled as a pressurized/refrigerated liquid; typically applied via soil injection.
- Urea: carbon-containing, typically handled as a bulk solid; typically broadcast pure or blended with conventional spreaders.

Those physical differences drive different infrastructure needs, logistics costs, safety regimes, and application patterns, which, in turn, influence nitrogen loss risk and why urea is often preferred despite known agronomic vulnerabilities (OSHA, n.d.).

How urea is made: ammonia + CO_2

Commercial urea production reacts ammonia with carbon dioxide at elevated pressure and temperature through an equilibrium process that includes internal recycle of unreacted NH_3/CO_2. The net chemistry is typically represented as:

$$2NH_3 + CO_2 \rightarrow CO(NH_2)_2 + H_2O$$ (Fertilizers Europe, 2019)

Industrial descriptions also often show the two-step pathway via ammonium carbamate as an intermediate:

$2NH_3 + CO_2 \rightleftharpoons NH_2COONH_4$ (ammonium carbamate)

$NH_2COONH_4 \rightleftharpoons CO(NH_2)_2 + H_2O$ (NZ Institute of Chemistry, n.d.)

The CO2 in the synthesis above typically comes from the reforming of the natural gas into hydrogen, and for this reason, urea production facilities are often tightly integrated with ammonia production. Because urea contains one carbon per molecule, each mole of urea produced corresponds (in net stoichiometry) to one mole of CO_2 incorporated. Practically, this translates into approximately 0.76 tons of CO2 per ton of urea produced. This fact leads to a common but incorrect extrapolation: "CO_2 is used to make urea, therefore CO_2 is sequestered."

What happens to urea after production: urea carbon typically returns to CO_2 during use

When urea fertilizer is applied to soils, it hydrolyzes rapidly in the presence of water and the enzyme urease, producing ammonia, which becomes ammonium in soil, and carbon dioxide. A simplified representation used in agronomy guidance is:

$$CO(NH_2)_2 + H_2O + \text{urease} \rightarrow 2NH_3 + CO_2$$ (UMN Extension, n.d.)

More detailed fertilizer-management references describe intermediate carbonate/bicarbonate species and note that urease activity is often greatest near the soil surface—one reason surface-applied urea can be prone to volatilization losses (USDA NRCS, n.d.).

Critically for carbon accounting, the Intergovernmental Panel on Climate Change (IPCC) national inventory methodology explicitly treats urea fertilization as a source of CO_2 emissions based on the carbon content of urea, with a Tier 1 default emission factor of 0.20 (kg C per kg urea) for CO_2-C emissions from urea applications (and notes that countries may develop more specific factors if data support it) (IPCC, 2006).

This inventory treatment reflects the underlying lifecycle reality: in typical use, urea carbon is not durably stored; it is transformed and generally re-emitted as CO_2 on agronomic timescales. Practically, the same CO2 that would have emitted by reforming natural gas is emitted, the emission is just delayed by at most a few months (UMN Extension, n.d.).

Shipping, handling, and application differences—and how they affect nitrogen performance and losses

The preference towards urea is explained by a practical combination of logistics, infrastructure compatibility, and application flexibility. At the same time, ammonia and urea present different nitrogen-loss risks in soil, and those risks shape best practices and product choice. It can be argued that if properly applied ammonia is a more effective fertilizer, "properly applied" being the key. In real life, the other advantages of urea have driven its application despite its relatively higher cost on a nitrogen basis.

Shipping and handling: pressurized hazardous liquid vs. bulk solid

Anhydrous ammonia is transported and stored under pressure (and in some cases refrigeration). This requires engineered systems, defined safety practices, and regulatory compliance. The Occupational Safety and Health Administration (OSHA) anhydrous ammonia standard addresses design and operation of ammonia systems (with scope limits), illustrating that ammonia handling is treated as a distinct industrial safety category (OSHA, n.d.). In agricultural distribution, anhydrous ammonia commonly moves from dealer to field in pressurized "nurse tanks," and extension and state guidance emphasize inspection, hoses/valves, and safe operating practices because the material is transferred under high pressure (MDA, n.d.). Because of the higher cost and regulatory burden of ammonia storage,

storage availability is often a bottle neck on logistics of ammonia, making management of inventory more complex and costlier

Urea, by contrast, is typically a stable bulk solid. It can be shipped and stored using conventional dry-bulk infrastructure (ports, terminals, railcars, trucks, warehouses, bags) without pressure containment. Urea is not operationally "free" of handling issues—caking and moisture sensitivity are well-known—but the logistics are generally simpler and common with those of many other agricultural commodities. Urea's limited downsides are not unique; moisture sensitivity and caking tendency are, for example, common with many feed products. Fertilizer-management references treat urea as a standard commodity that is broadly compatible with existing distribution and application equipment (UMN Extension, n.d.).

Application: injection vs. broadcast

Ammonia is commonly applied via soil injection, which places the fertilizer below the surface and relies on good soil closure to prevent gaseous loss. Safety-oriented extension publications emphasize that this is specialized field equipment and that handling and transfer systems must be maintained to prevent uncontrolled release (NDSU Extension, n.d.).

Urea can be broadcast, banded, incorporated, or applied as a solution (including as part of UAN solutions). Extension fertilizer guidance emphasizes that urea is often favored for operational simplicity, but that surface application without incorporation or rainfall can create conditions for ammonia loss (UMN Extension, n.d.).

Soil nitrogen behavior and loss pathways

Once applied, both ammonia- and urea-derived nitrogen ultimately move through the familiar soil nitrogen cycle (ammonium → nitrate), but the front-end chemistry differs.

With urea, hydrolysis can create localized pH increases around dissolving granules or droplets, shifting the ammonium/ammonia equilibrium toward gaseous NH_3 and increasing the risk of ammonia volatilization, especially when urea is surface-applied and not moved into the soil by incorporation or timely rainfall. University and USDA/NRCS references explicitly describe this hydrolysis reaction and its management implications: incorporating and adjusting to rainfall timing is key to reducing nitrogen loss risk (UMN Extension, n.d.).

With injected anhydrous ammonia, placement below the surface generally reduces direct volatilization relative to surface-applied urea, provided injection and sealing are done correctly. So, in general, one could argue that ammonia is a more efficient source of nitrogen. Over time, however, both sources can be nitrified to nitrate and become susceptible to losses via leaching and denitrification under wet conditions. The practical distinction is that urea has a well-known early-stage vulnerability to surface volatilization that ammonia injection can often avoid (UMN Extension, n.d.).

Why urea is often preferred despite deficiencies

Urea's continued preference in many markets is thus largely explained by two structural advantages:

- Logistics and infrastructure fit. Urea's bulk-solid form is compatible with global dry-bulk trade and widespread fertilizer distribution systems, whereas anhydrous ammonia requires specialized pressurized storage and handling infrastructure (OSHA, n.d.).
- Operational flexibility. Urea is readily broadcast and blended and can be applied with widely available equipment; ammonia typically requires injection equipment and suitable soil conditions and safety practices (UMN Extension, n.d.).

Lastly, while urea has a real loss risk, the risk is manageable. Agronomy references describe practical steps to reduce volatilization risk for urea, such as incorporation, timely rainfall/irrigation, and management practices that address surface urease activity. These mitigations can add cost, but they are less structurally burdensome than building an anhydrous ammonia handling network where none exists (UMN Extension, n.d.).

In short, urea's market position is primarily a logistics-and-practice trade-off outcome.

Using CO_2 in urea manufacture is not carbon sequestration

Carbon sequestration implies durable storage that prevents carbon from returning to the atmosphere on meaningful timescales (typically decades to centuries), as in geologic storage or mineralization into stable carbonates. The IPCC's carbon capture and storage assessment explicitly distinguishes between (i) storage through fixation as inorganic carbonates ("mineral sequestration") and (ii) industrial utilization of CO_2 as a fluid or chemical feedstock (IPCC, 2005).

Urea production falls into industrial utilization, not durable storage. Although the CO_2 is chemically incorporated into urea, the dominant use case (fertilizer) converts that carbon back to CO_2 after application. Agronomy references show the hydrolysis reaction explicitly producing CO_2, and the IPCC inventory guidance treats urea fertilization as a CO_2 emission source based on urea's carbon content (UMN Extension, n.d.).

Therefore, "CO_2-to-urea" is best described as temporary CO_2 utilization with delayed re-emission, not sequestration.

A related point is scale and context: the IEA notes that CO_2 use today is substantial and that urea manufacturing is one of the largest existing CO_2 utilization pathways (on the order of ~130 $MtCO_2$ per year in IEA tracking). That prevalence does not imply sequestration; it mainly reflects that urea is a large commodity market that can consume concentrated CO_2 streams (IEA, n.d.).

Why it is generally not meaningful to call it carbon recycling

"Recycling" implies a loop in which carbon is recovered after use and returned to production, displacing new carbon inputs and reducing net emissions. In the mainstream lifecycle of fertilizer urea, the carbon is incorporated into urea at a point source, then released diffusely across agricultural land as CO_2 after application. Once dispersed, it is not practically captured and routed back to the urea plant, so the carbon flow is not a closed industrial cycle.

This framing aligns with broader carbon capture and utilization (CCU) assessments: climate benefit claims for CO_2 use depend on lifecycle accounting, the carbon source (fossil vs. biogenic vs. direct air capture), and—critically—whether the product retains carbon long-term or simply returns it to the atmosphere after short use. IEA analysis emphasizes that CO_2 use can support climate goals in some contexts, but benefits are application-specific and require comprehensive lifecycle assessment; some applications involve permanent retention (notably certain building materials), while many do not (IEA, 2019).

Urea fertilizer is, in most cases, a short-lived carbon carrier rather than a circular carbon product.

Using biogenic urea would make urea carbon neutral, but once again, one could not claim a recycle per se, although an emission reduction could be claimed to the extent one can prove that an equivalent amount of conventional urea has been displaced. In general, the burden of this proof is not insignificant but would be relatively easy for ethanol producers.

Appendix 6: The Ammonia–Urea Nexus: Why Urea Matters and the Implications for Distributed Green Ammonia

A common narrative in U.S. fertilizer policy holds that the shale gas revolution has substantially restored domestic nitrogen security. Net import reliance for ammonia has fallen from roughly 30% in 2015 to under 10% by 2022, and domestic ammonia capacity continues to expand (U.S. Geological Survey, 2026). This appears reassuring.

Our analysis indicates that this conclusion is incomplete — and, in important respects, partly misleading. U.S. agriculture remains highly vulnerable to external supply shocks, not because of ammonia, but because of urea: the derivative nitrogen product toward which American farming is structurally migrating. The nation has reduced its dependence on ammonia imports while simultaneously increasing its dependence on urea imports from a narrow set of geopolitically exposed suppliers. The vulnerability has not been eliminated; it has been displaced one step downstream in the nitrogen value chain, where it is less visible but no less consequential.

As this document is being written, the supply security vulnerabilities are transitioning from possibility to reality. Following the U.S.-Israeli military attack on Iran beginning in late February 2026, Iran imposed a de facto blockade of the Strait of Hormuz — the sole maritime exit from the Persian Gulf. Qatar, the second-largest source of U.S. urea imports, is 100% dependent on Hormuz transit; its urea production facilities at Mesaieed and Ras Laffan have no alternative route to open ocean. On March 3, QatarEnergy confirmed it had halted production of LNG and all downstream products — explicitly including urea — at both facilities following direct military strikes (Carnegie Endowment for International Peace, 2026; Kpler, 2026). Saudi Arabia's major fertilizer export terminals at Jubail and Ras al Khair are similarly inside the Gulf and require Hormuz transit; no pipeline or Red Sea routing exists for fertilizer products. Of the three principal Middle Eastern suppliers to the U.S. urea market, only Oman — whose main ports face the Gulf of Oman rather than the Persian Gulf — is partially insulated from the chokepoint, though regional instability, elevated insurance costs, and shipping disruption affect it as well.

As of mid-March, vessel tracking shows a build-up of fertilizer-laden carriers at Gulf anchorages from Ras Laffan to Fujairah, with transit status uncertain (Kpler, 2026; The Watchers, 2026). Urea prices have spiked: Egyptian urea reached $625/mt (up 25%), Saudi producers raised FOB benchmarks from ~$402 to $450/mt, and U.S. prices — already at $508/mt in February — are likely to climb further as spring application season demand intensifies (Intratec, 2026; Middle East Monitor, 2026; Farmdoc Daily, 2026). The American Farm Bureau Federation has urged the President to deploy the Navy to protect fertilizer shipments and suspend countervailing duties on imported fertilizer (American Farm Bureau Federation, 2026).

Understanding this requires tracing the relationship between ammonia and urea — and the agronomic, economic, and logistical forces that are shifting U.S. nitrogen demand between the two.

Ammonia as the Universal Precursor

All major synthetic nitrogen fertilizers begin with anhydrous ammonia (NH_3), produced via the Haber-Bosch process from natural gas and atmospheric nitrogen. Ammonia can be applied directly to soil as a fertilizer (82% N content, the highest of any commercial source), or it can be converted into derivative products: urea (46% N), urea ammonium nitrate solutions (UAN, 28–32% N) — a liquid blend of urea and ammonium nitrate dissolved in water, named for its two nitrogen-bearing components, ammonium nitrate, ammonium sulfate, and ammonium phosphates. Approximately 88% of U.S. ammonia consumption is used for fertilizer in one form or another (U.S. Geological Survey, 2026).

The U.S. uses three primary nitrogen fertilizer forms: anhydrous ammonia (AA), urea, and UAN. Historically, the direct application of AA dominated U.S. nitrogen fertilization, particularly in the Corn Belt, where fall soil injection ahead of spring planting was standard practice. AA remains the cheapest nitrogen source per pound of N, because it avoids the additional processing steps and energy costs required to convert ammonia into urea or UAN.

The Shift Away from Direct Ammonia Application

Despite its cost advantage, direct AA application has been in gradual structural decline in the United States, while consumption of urea and UAN has trended upward. Several reinforcing factors drive this shift:

- **Safety and handling constraints.** Anhydrous ammonia is a gas under normal atmospheric conditions and must be stored and transported as a liquid under pressure, requiring specialized tanks, equipment, and trained applicators. Increasingly stringent hazardous materials regulations, rising insurance and liability costs, and the shrinking number of qualified applicators have raised the effective cost and logistical burden of AA use — costs that do not appear in the per-ton price.
- **Agronomic flexibility.** Urea and UAN can be broadcast, banded, or dissolved for fertigation, and applied across a wider range of timing windows and soil conditions. AA requires subsurface injection and is agronomically unsuitable for fall application in warmer soils (much of the South and Southeast) and increasingly risky in regions where warm falls extend late into the season. As climate variability narrows the reliable cold-soil window for fall AA injection, urea and UAN gain share.
- **Precision agriculture compatibility.** Modern variable-rate application systems and split-application strategies are easier to implement with granular urea or liquid UAN than with pressurized ammonia. The shift toward enhanced efficiency fertilizers (EEFs) — urease inhibitors, controlled-release coatings — further favors urea-based products. However, polymer-coated controlled-release fertilizers carry their own emerging environmental concerns: as the non-biodegradable polymer coatings break down in soil, they release microplastic particles that accumulate over time, with potential long-term effects on soil microbiology, heavy metal mobility, and broader environmental health. A 2025 University of Missouri study (Salehi et al., 2025) documented the mechanisms by which these coatings generate microplastics, and a long-term UK field study (1966–2022) found that microplastic concentrations in agricultural soils increased at higher rates where inorganic fertilizers, including coated products, were applied (Dobson et al., 2024).
- **Infrastructure and labor.** The farm-level equipment base for AA is aging, and younger operators are less likely to invest in dedicated ammonia infrastructure. Meanwhile, urea handling requires only conventional dry fertilizer equipment.

The net result is that anhydrous ammonia, urea, and UAN now hold roughly equal market shares of U.S. nitrogen consumption by volume, where AA was once clearly dominant. In key states like

Minnesota, urea has already surpassed AA as the primary nitrogen source. This is not a decline in nitrogen demand — U.S. nitrogen application rates per acre for corn have increased roughly 11% since 2002, and total nitrogen consumption stands at approximately 14.9 million metric tons (Farmdoc Daily, 2025; U.S. Geological Survey, 2026). The demand is growing; the delivery form is shifting decisively toward urea and urea-based products.

The Import Dependence Implication

This structural shift has a direct consequence for trade exposure. The United States produces most of the ammonia it consumes — net import reliance for ammonia has fallen from roughly 30% in 2015 to under 10% by 2022, thanks to shale gas-era capacity expansion (U.S. Geological Survey, 2026). But the U.S. does *not* produce enough urea to meet its growing share of nitrogen demand. Domestic urea production covers only 55–60% of consumption, with the remainder imported from geopolitically concentrated sources (Russia, Qatar, Saudi Arabia) (U.S. Import Data, 2026; The Fertilizer Institute, 2025).

In other words, the shift from direct AA application to urea-based fertilization is simultaneously a shift from a domestically secure nitrogen supply chain to a more import-dependent one. Every ton of nitrogen that moves from the AA column to the urea column increases the nation's exposure to global urea trade dynamics, foreign supply disruptions, and the price-setting behavior of a small number of exporting countries. This is the structural context in which the statistics below should be read.

Consumption

U.S. urea consumption reached approximately 9.9 million metric tons in 2024, a 4% increase over 2023 (IndexBox, 2025a; Straits Research, n.d.). Consumption peaked at roughly 11 million tons in 2021 and has remained somewhat below that level since. Total U.S. demand for urea (including all end-use forms) is estimated at approximately 16 million tons annually (IndexBox, 2026). The agricultural sector is the primary demand driver, followed by industrial applications including diesel exhaust fluid (DEF/AdBlue), resins, adhesives, and plastics.

Domestic Production

Output

U.S. urea production rose to approximately 5.8 million tons in 2024, a 3.2% year-over-year increase. Production has expanded at a compound annual growth rate (CAGR) of roughly 4% from 2013 to 2024, with the fastest single-year increase (33%) recorded in 2018 as new shale-gas-era capacity came online (IndexBox, 2025a; U.S. Geological Survey, 2026).

Capacity and Major Producers

Total U.S. ammonia production capacity stands at approximately 19.2 million tons, of which roughly 9.7 million tons feeds urea synthesis and the remainder goes to other nitrogen products (anhydrous ammonia, ammonium nitrate, UAN, etc.). Natural gas-based plants account for approximately 92% of U.S. urea production (Statista, 2020a). As of 2019, there were 22 urea-producing facilities in the United States. Key producers by nameplate capacity:

Company	***Urea Capacity (million mt)***	***Notes***
CF Industries	~6.21	Largest U.S. producer; Donaldsonville, LA complex has 6 ammonia plants and 5 urea plants
Nutrien	~2.02	Second-largest; multiple North American facilities
Koch Fertilizer	—	Significant capacity; privately held
LSB Industries	—	~900,000 t/yr ammonia capacity across three sites (El Dorado, AR; Cherokee, AL; Pryor, OK)

CF Industries operates 16 ammonia plants across North America with a total average annual ammonia capacity of 10.4 million tons. Its Donaldsonville complex alone produces nearly eight million tons of nitrogen products annually depending on product mix (CF Industries, 2024, 2026). The U.S. remains structurally import-dependent for urea. Domestic production covers only about 55–60% of consumption; the remainder is met through imports (U.S. Import Data, 2026). Volume and Trends:

- 2024: 5.1 million tons (up ~8.5% after two years of decline)
- Historical peak: ~8.1 million tons (2015)

General trend: Imports have declined from the 2015 peak as domestic capacity expanded, but remain substantial.

Top Source Countries (2024)

Country	***Volume (million mt)***	***Share of Imports***
Russia	1.4	~27%
Qatar	1.0	~20%
Canada	0.53	~10%
Saudi Arabia	~0.48	~9%
Algeria	~0.46	~9%
Nigeria	—	Fastest-growing supplier (CAGR +38.5%, 2013–2024)
Oman, UAE, Trinidad & Tobago, China	—	Combined ~17%

Russia, Qatar, and Canada together accounted for approximately 58% of total U.S. urea imports by volume (U.S. Import Data, 2026).

Import Values and Prices

Year	***Import Value***	***Avg. Import Price ($/ton)***
2022	~$3.23 billion	~$630 (peak)
2023	~$2.01 billion	~$392
2024	~$1.87 billion	~$342
2025 (Jan–Nov)	~$2.02 billion	—

The ~40% decline in import value from 2022 to 2024, despite relatively stable volumes, reflects the sharp normalization of global fertilizer prices following the 2021–2022 energy and commodity price spike.

Price Variation by Source (2024)

Significant price differentials exist among suppliers. Chinese urea commanded the highest import price (~$523/ton), while Russian urea was among the lowest (~$315–321/ton) (U.S. Import Data, 2026).

Regional Price Dynamics

Monthly price data from Intratec (Jan 2016–Feb 2026) provides granular visibility into global urea price behavior across seven regional markets: U.S. (granular), China, Southeast Asia, South America (granular), Middle East (granular), Europe (granular), and Africa (granular) (Intratec, 2026).

Current Prices and the 2024–2026 Trajectory

As of February 2026, U.S. granular urea stands at $508/mt, representing a 42% increase from the December 2024 low of $357/mt. The full-year 2024 U.S. average was approximately $361/mt — consistent with the $342/mt average import price reported in trade data, with the ~$19/mt differential reflecting the expected markup between FOB import pricing and domestic delivered/spot pricing.

The February 2026 price, however, signals renewed tightness heading into the spring application season, well above 2024 averages and approaching levels last seen during the tail end of the 2021–2022 crisis.

The 2021–2022 Price Spike in Regional Perspective

The Intratec data reveals the sharply differentiated regional impact of the 2021–2022 crisis (Intratec, 2026):

Europe bore the most extreme price spike, peaking at $1,200/mt in March 2022 — roughly 4.8× its pre-crisis level (~$250/mt in mid-2020). European prices remained above $900/mt for most of 2022, reflecting the region's acute natural gas cost exposure.

The U.S. peaked at $854/mt (March 2022), about 3.4× its pre-crisis level, tracking Middle East export pricing more closely than European prices.

China was the most insulated market, peaking at only ~$480/mt (October 2021) before declining, reflecting Beijing's export controls that effectively decoupled Chinese domestic prices from global markets. By mid-2022, Chinese prices had already fallen below $400/mt while all other regions remained elevated.

The domestic U.S. peak of $854/mt significantly exceeds the $630/mt average import price reported for 2022 in trade statistics, which is expected: March was the most extreme month, and annual import price averages smooth across the full year and across cheaper-origin suppliers.

The U.S.–China Spread as a Market Stress Indicator

The price differential between U.S. and Chinese urea is analytically revealing. As of February 2026, the U.S.–China spread stands at $257/mt ($508 vs. $251) — the widest in the dataset outside the 2021–2022 crisis window. This suggests structural tightness in non-Chinese markets, driven by a combination of spring demand, supply constraints, and China's continued export restraint. During the 2021–2022 crisis, the spread briefly exceeded $400/mt. In the pre-crisis period (2016–2020), the spread was typically small and sometimes negative, as Chinese prices occasionally exceeded U.S. prices in a more connected global market. The persistent and widening spread since 2023 suggests that China's decoupling from global urea trade — through export quotas and administrative inspection requirements — is becoming a structural feature rather than a temporary disruption (Hellenic Shipping News / Reuters, 2024; Jamestown Foundation, 2024; CZ App, 2025; Hu et al., 2025). China's primary mechanism for restricting urea exports is the CIQ (China Inspection and Quarantine) export inspection certificate[16], introduced in October 2021 as domestic fertilizer prices surged.

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[16] Before any urea shipment can leave China, the exporter must obtain this certificate — an administrative gate that Beijing can open or close at will by adjusting processing timelines, issuance windows, and volume caps. The system functions as a discretionary export valve rather than a formal ban: during periods of restriction, the inspection process simply slows or halts, achieving near-total export suppression through bureaucratic friction. In the first half of 2024, this mechanism reduced Chinese urea exports by 86% year-over-year to just 140,000 tons. For 2025, the system has become more explicitly formalized: the China Nitrogen Fertilizer Association allocated a quota of just two million tonnes (well below initial expectations of four million), with inspection certificate applications limited to a May–September window, a customs declaration deadline of October 15, and a requirement that ex-factory prices not exceed early-May levels. The inspection system has now been in continuous operation since late 2021, and each iteration has added specificity rather than loosening — suggesting that China's partial withdrawal from the global urea export market is a deliberate,

The U.S.–Middle East Spread and Import Arbitrage

The U.S.–Middle East price spread is the key signal for import economics, since Middle Eastern producers (Qatar, Saudi Arabia, Oman) are among the lowest-cost global exporters and the largest non-Russian suppliers to the U.S. market. During most of the 2016–2020 period, the U.S. traded at a modest premium to Middle East prices ($20–60/mt), providing a stable arbitrage incentive for eastbound shipments.

During the 2021–2022 crisis, this relationship briefly inverted — Middle East prices exceeded U.S. prices for parts of late 2021 and early 2022, meaning the arbitrage incentive to ship to the U.S. temporarily collapsed during the global scramble for supply. This is a supply security red flag: in a severe disruption, the U.S. is not the price-setter and can be outbid by other import-dependent regions (notably South Asia and Brazil).

As of February 2026, the U.S.–Middle East spread has normalized at approximately $23/mt ($508 vs. $485), a thin margin that suggests the import channel is functioning but not offering a significant price advantage to U.S. buyers.

Selected Regional Price Data (USD/mt)

Period	*U.S. (Gran)*	*China*	*Middle East (Gran)*	*Europe (Gran)*	*U.S.–CN Spread*	*U.S.–MDE Spread*
Jun 2020	216	232	221	291	–16	–5
Dec 2020	249	279	272	352	–30	–23
Jun 2021	428	436	453	377	–8	–25
Sep 2021	539	436	501	573	+103	+38
Nov 2021	812	392	903	978	+420	–91
Mar 2022	**854**	**470**	**875**	**1,200**	**+384**	**–21**

long-term policy posture driven by domestic food security priorities, not a transient response to crisis conditions.

Jun 2022	496	472	618	946	+24	–122
Sep 2022	652	364	679	976	+288	–27
Dec 2022	468	387	500	883	+81	–32
Jun 2023	341	316	286	444	+25	+55
Dec 2023	339	359	321	458	–20	+18
Jun 2024	334	305	338	444	+29	–4
Dec 2024	357	235	348	464	+122	+9
Jun 2025	423	235	401	589	+188	+22
Dec 2025	423	231	408	567	+192	+15
Feb 2026	**508**	**251**	**485**	**638**	**+257**	**+23**

Note: Negative U.S.–MDE spreads indicate that Middle East export prices exceeded U.S. domestic prices — i.e., the import arbitrage incentive collapsed. Full monthly series available in accompanying interactive chart.

Price Data Source

Monthly price data: Intratec (www.intratec.us). Price designations: (Fi) = Final, (P) = Preliminary. All prices in USD per metric ton. Regional benchmarks: U.S. Granular, China (FOB), Southeast Asia, South America Granular, Middle East Granular, Europe Granular, Africa Granular.

Trade Policy Context

Russian fertilizer is currently exempt from IEEPA tariffs, with 0% tariff rates on all fertilizer imports. The United States Mexico Canada Agreement (USMCA) partners (Canada, Mexico) are also exempt from reciprocal tariffs. In April–May 2025, U.S. urea imports fell 18% overall, suggesting some trade flow disruption or seasonal demand softening (U.S. Import Data, 2026).

Other Structural Observations

Decarbonization efforts (CCS retrofits at CF Industries Donaldsonville, LSB Industries El Dorado; Ammonia Energy Association, 2025) target CO_2 streams from non-urea ammonia production and do not directly address the urea volume gap — and may, through 45Q incentive structures, indirectly widen it by favoring CO_2 sequestration over its use as urea feedstock. Of the 19.2 million tons of U.S. ammonia production capacity, approximately 9.7 million tons feeds urea synthesis and 12.5 million tons goes to other nitrogen products (anhydrous ammonia, ammonium nitrate, UAN, DEF, etc.). The current CCS projects — CF Industries' 2 Mt CO_2/yr compression and dehydration facility at Donaldsonville (operational July 2025), a planned ~500,000 t CO_2/yr facility at Yazoo City, Mississippi (targeted 2028), and LSB/Lapis Carbon Solutions' ~450,000 t CO_2/yr project at El Dorado, Arkansas (targeted late 2026) — capture CO_2 from the non-urea ammonia stream, which was previously vented (CF Industries, 2024; Ammonia Energy Association, 2025). In the current configuration, there is no direct feedstock competition with urea synthesis. The more consequential risk is economic and structural. At an integrated complex like Donaldsonville, CO_2 streams are to some degree fungible across product lines. The Section 45Q tax credit pays \$85 per ton of CO_2 sequestered over a 12-year period. Urea synthesis consumes approximately 0.73 t CO_2 per ton of urea produced (stoichiometric: $2\ NH_3 + CO_2 \rightarrow (NH_2)_2CO + H_2O$). At the 45Q rate, the implicit opportunity cost of *using* CO_2 for urea rather than sequestering it is roughly \$62 per ton of urea — a non-trivial figure against a 2024 average import price of \$342/ton. If 45Q credits make it more profitable to sequester CO_2 than to convert it into urea, the incentive structure could gradually favor shifting ammonia capacity away from urea synthesis toward "clean ammonia" + CCS. This dynamic would be especially pronounced if green or blue ammonia gains a price premium in export or industrial markets (clean hydrogen economy, maritime fuel, power generation), pulling ammonia volumes away from urea conversion entirely. The net effect: the U.S. could become simultaneously a lower-carbon ammonia producer and a more import-dependent urea consumer — an arguably perverse outcome from a supply security standpoint, and one that mirrors the broader pattern of Section 45Q incentives rewarding the disposal of carbon rather than its utilization as a chemical building block.

Conclusion: Distributed Green Ammonia as a Supply Security Pathway

The evidence assembled in this document identifies a key issue: U.S. agriculture has not eliminated its nitrogen supply vulnerability — inexpensive natural gas and increased domestic ammonia production have displaced it one step downstream, from ammonia to urea, where it is less visible but no less consequential. Domestic ammonia self-sufficiency has improved dramatically since 2015, but the agronomic shift toward urea and UAN means that an increasing share of the nation's nitrogen reaches cropland in a form the country does not produce in sufficient quantity. The result is structural dependence on urea imports from a narrow set of geopolitically concentrated suppliers — Russia, Qatar, Saudi Arabia — with thin arbitrage margins, demonstrated price volatility (a 3–4× spike in 2021–2022), and no domestic buffer adequate to absorb a sustained disruption. Current federal policy does not resolve this contradiction. If anything, it deepens it:

- **The 45Q tax credit** (\$85/t CO_2 sequestered) creates an economic incentive to dispose of CO_2 rather than use it as urea feedstock, implicitly discouraging the conversion of domestically produced ammonia into domestically consumed urea. The ~\$62/t urea opportunity cost of using CO_2 for synthesis rather than sequestration is non-trivial and will become more significant as CCS capacity expands across Gulf Coast nitrogen complexes.
- **The IRA's decarbonization incentives** (45V clean hydrogen credit, 45Q) structurally favor ammonia production pathways that either capture CO_2 (blue ammonia) or never produce it (green ammonia). Both pathways disfavor urea synthesis at the point of production — blue ammonia by diverting CO_2 to sequestration, green ammonia by generating no process CO_2 at all. The policy architecture accelerates ammonia decarbonization while allowing the urea import gap to widen.
- **No mechanism exists** to reconnect domestic nitrogen *production* with domestic nitrogen *application* in the form the market increasingly demands. The nation is decarbonizing its ammonia industry and expanding its urea import bill simultaneously — an arguably perverse outcome from a supply security standpoint.

Green Distributed Ammonia: Bypassing the Urea Bottleneck

Distributed green ammonia (DGA) — small- to mid-scale electrolytic ammonia production co-located with renewable energy resources and agricultural demand — offers one of the few pathways that resolves this structural contradiction, but it does so by fundamentally reframing the problem. DGA does not solve the urea gap. It bypasses it.

Green ammonia produced via electrolysis generates no process CO_2. Urea synthesis requires approximately 0.73 t CO_2 per ton of product (stoichiometric: $2\ NH_3 + CO_2 \rightarrow (NH_2)_2CO + H_2O$). A green ammonia plant *physically cannot produce urea* at the point of production without sourcing CO_2 externally — from direct air capture, bioethanol fermentation, biogas upgrading, or flue gas. This is not a limitation of DGA; in the context of the supply security problem documented here, it is a structural advantage. DGA naturally returns nitrogen delivery to its most concentrated and entirely domestic form: anhydrous ammonia at 82% N, produced from air, water, and renewable electricity, with zero import dependency and zero fossil feedstock exposure.

The Agronomic Fit: The Upper Midwest

The Corn Belt — Minnesota, Iowa, Illinois, Indiana, Nebraska — is where this argument has the most immediate practical relevance, for two reinforcing reasons:

- **First, it is the last stronghold of direct AA application.** Fall injection of anhydrous ammonia into cold soils ahead of spring corn planting remains standard agronomic practice across the Upper Midwest, supported by established equipment infrastructure, applicator networks, and the NuStar ammonia pipeline system spanning 2,000+ miles from Gulf Coast production to heartland demand (U.S. Government Accountability Office, 1998). The shift from AA to urea, while real and ongoing, is less advanced here than in warmer-climate agricultural regions (the Southeast, California) where AA is agronomically impractical. If DGA can produce ammonia locally, it can arrest the AA-to-urea substitution in precisely the region where that substitution is most consequential for national import dependence.
- **Second, the Upper Midwest has the renewable energy resource base to support DGA.** Curtailed wind generation in Iowa, Minnesota, and the Dakotas — electricity that is produced but cannot be absorbed by the grid — represents a low-cost or near-zero-cost energy input for electrolytic hydrogen production. Co-locating ammonia synthesis with curtailed renewables and proximate agricultural demand collapses the supply chain from a global commodity trade (natural gas → Gulf Coast ammonia → rail/barge → urea plant → import blending → distributor → farm) to a regional or local production loop (wind/solar → electrolyzer → ammonia synthesis → on-farm application).

The Remaining Challenge: Handling and Application Barriers

The agronomic, regulatory, and labor barriers that have driven the long-term shift from AA to urea are real, and DGA does not automatically eliminate them. Anhydrous ammonia remains a toxic, high-pressure material requiring specialized equipment, trained applicators, and careful management. The aging farm-level infrastructure for AA handling, the shrinking pool of qualified applicators, and the regulatory burden of hazardous materials transportation are structural headwinds that will not reverse simply because the production technology changes. Two emerging developments may partially address this:

- **Aqua ammonia** (ammonia dissolved in water, typically 20–25% NH_3) is a lower-pressure, less volatile alternative that can be stored and handled with substantially reduced safety requirements. Several DGA technology developers are targeting aqua ammonia as the end product, trading nitrogen concentration for logistical simplicity. While the economics of transporting a more dilute product are less favorable over long distances, they may be acceptable within a localized production-and-application radius.
- **Smaller-scale, on-farm or cooperative-scale application systems** designed specifically for DGA output — including systems integrated with precision agriculture platforms for variable-rate, in-season nitrogen management — could lower the equipment and expertise barrier. This is an active area of technology development, though no dominant design has yet emerged.

The Counterargument: Green Urea from Biogenic CO_2

An obvious objection to the "DGA bypasses urea" framing is that green ammonia could be combined with biogenic CO_2 — particularly from corn ethanol fermentation — to produce "green urea" domestically. The U.S. ethanol industry and the Corn Belt nitrogen demand are geographically co-located, and the CO_2 stream from fermentation is nearly 100% pure, requiring minimal purification. The question is whether this pathway can scale enough to meaningfully close the urea import gap.

The theoretical CO_2 budget is more than sufficient. U.S. ethanol production reached a record 16.22 billion gallons in 2024 (Renewable Fuels Association, 2025). Corn ethanol fermentation produces approximately 2.87 kg of biogenic CO_2 per gallon of ethanol (stoichiometric), yielding a total biogenic fermentation CO_2 stream of roughly **46.6 million metric tons per year**. Urea synthesis requires 0.73 t CO_2 per ton of urea. In principle, the available ethanol CO_2 could support production of ~63.8 million tons of urea — over 6× total U.S. consumption (~9.9 Mt) and more than 12× the current import gap (~5.1 Mt). CO_2 availability is emphatically not the constraint.

Ammonia is the constraint. Producing 63.8 Mt of urea would require ~36.2 Mt of ammonia — nearly double total U.S. ammonia production capacity (19.2 Mt). To close just the import gap (5.1 Mt urea) would require ~2.9 Mt of ammonia and ~3.7 Mt of biogenic CO_2 (roughly 8% of available fermentation CO_2). That ammonia requirement — whether gray, blue, or green — represents a substantial industrial build-out regardless of how the CO_2 is sourced. In practice, however, the pathway faces four compounding and overlapping constraints that severely limit realistic scale:

- **First, plant-scale mismatch.** There are approximately 198 ethanol plants in the U.S. (U.S. Energy Information Administration, 2025), averaging roughly 115,000–235,000 metric tons CO_2/year each from fermentation. Conventional urea synthesis loops operate economically at scales of 500,000–2,000,000+ t/year of finished product. A single ethanol plant's CO_2 output is at or below the minimum economic scale for urea synthesis. Closing this gap would require either aggregating CO_2 from multiple ethanol plants via pipeline — adding significant infrastructure cost and overcoming the persistent local opposition that has stalled Midwest CO_2 pipeline development. [17]

[17] Navigator CO2 Ventures, backed by BlackRock, abandoned its proposed 1,300-mile Heartland Greenway pipeline in October 2023 after failing to secure permits. Summit Carbon Solutions' $5.5 billion, 2,500-mile Midwest Carbon Express — designed to collect CO_2 from 57 ethanol plants across five states and transport it to underground storage in North Dakota — has faced years of landowner resistance, eminent domain litigation, and regulatory setbacks: South Dakota denied Summit's permit application twice and enacted a law prohibiting eminent domain for CO_2 pipelines; North Dakota denied the permit; multiple Iowa counties filed suit to overturn the Iowa Utilities Commission's conditional approval; and 78% of Iowans polled opposed the use of eminent domain for CO_2 pipelines. As of early 2026, Summit has not begun construction and is exploring an alternative route to the Denver-Julesburg Basin in Colorado/Wyoming (Iowa Public Radio, 2025; Bloomberg Law, 2025; Oil & Gas Journal, 2025). The difficulty of building CO_2 aggregation infrastructure in the Midwest is not hypothetical — it is a demonstrated, multi-year political and regulatory reality that must be factored into any assessment of the green urea pathway's scalability— nor is developing small-

- **Second, 45Q competition for the CO_2 stream.** This is the same perverse incentive structure identified earlier in this document, now operating at the ethanol plant rather than the ammonia plant. The Section 45Q tax credit pays $85 per ton of CO_2 permanently sequestered. Currently, only about 25% of U.S. ethanol plants capture their fermentation CO_2, but the pipeline and sequestration infrastructure is expanding rapidly — driven precisely by 45Q economics (CCarbon, 2025; Growth Energy, 2025). At $85/t CO_2, the financial incentive overwhelmingly favors burying biogenic CO_2 over using it as urea feedstock. The CO_2 value in urea synthesis is implicit (it becomes part of the product rather than generating a tax credit), while the CO_2 value in sequestration is explicit and bankable. Every ton of biogenic CO_2 that enters a sequestration well is a ton unavailable for urea — and under current policy, the well wins. If the full ethanol industry were to adopt CCS (the Government Accounting Office - GAO - estimates 45 million metric tons of sequestration potential (Renewable Fuels Association, 2022)), the biogenic CO_2 stream that theoretically could support green urea would instead be locked underground. This means that should the regulatory and public perception barrier to CO2 pipeline – identified earlier - fall, it would be much more economically sensible for an ethanol plant to proceed with CCS rather than aggregating CO2 for urea production.
- **Third, geographic and infrastructure mismatch.** Ethanol plants and corn-belt nitrogen demand are indeed co-located — but existing urea synthesis capacity is not. U.S. urea production is concentrated on the Gulf Coast (Donaldsonville, LA; Yazoo City, MS; Waggaman, LA), connected to demand centers via the NuStar pipeline, rail, and barge. Producing green urea in the Midwest would require building new urea synthesis capacity co-located with ethanol CO_2 sources — a capital-intensive proposition that competes for investment with Gulf Coast brownfield expansions and lacks the deepwater export optionality that Gulf Coast facilities enjoy.

scale modular urea synthesis technology — which does not yet exist at commercial readiness and would face unfavorable economies of scale relative to the large integrated Gulf Coast complexes it would be competing against.

- **Fourth, added complexity versus DGA.** Green urea from biogenic CO_2 requires the full chain: electrolyzer → hydrogen → ammonia synthesis → urea synthesis, plus CO_2 capture, purification, compression, and transport from the ethanol plant. DGA for direct application requires only: electrolyzer → hydrogen → ammonia synthesis. Each additional process step adds capital cost, parasitic energy load, and operational complexity. The end product (urea, 46% N) is less concentrated than the intermediate (anhydrous ammonia, 82% N), meaning more material must be transported and applied per unit of nitrogen delivered. The pathway makes economic sense only where the handling and application barriers to direct ammonia use are genuinely insurmountable — and in the Upper Midwest, they are not.
- Green urea from ethanol-sourced biogenic CO_2 is a technically feasible but practically constrained pathway. A small number of large, well-sited facilities — perhaps co-located with the largest ethanol complexes (ADM Decatur, POET Chancellor) where CO_2 volumes approach minimum economic scale for urea synthesis — could produce meaningful quantities. But the pathway cannot plausibly scale to close the 5+ million-ton annual import gap without a fundamentally different policy framework that either values CO_2 utilization on par with CO_2 sequestration or invests in distributed-scale urea synthesis technology and Midwest CO_2 pipeline aggregation infrastructure. Under current 45Q economics, the CO_2 is worth more underground than in a urea granule.

Summary: Reframing the Value Proposition

The conventional framing of green ammonia positions it primarily as a decarbonization play — a way to reduce the carbon intensity of nitrogen fertilizer production. Our analysis to date indicates that DGA can be a local economic development play. The analysis in this document strengthens a third, equally important framing: **distributed green ammonia is a supply security play.**

The U.S. has spent the past decade reducing its dependence on ammonia imports while inadvertently increasing its dependence on urea imports. Current decarbonization policy, particularly the 45Q and 45V credit structures, is likely to accelerate this divergence by favoring CO_2 sequestration over CO_2 utilization for urea synthesis. The result is a nitrogen supply chain that is simultaneously cleaner and more fragile — less carbon-intensive in production, but more exposed to the geopolitics of international urea trade.

DGA offers a pathway that can address both dimensions: it decarbonizes nitrogen production and reduces trade exposure by delivering nitrogen in its most concentrated, entirely domestic, import-free form. The opportunity is most immediate in the Upper Midwest, where the renewable energy resource base and the concentration of nitrogen-intensive corn production converge with a still-substantial tradition of direct ammonia application — though one that has been in decline as upgrading and urea-based products have gained share. Reversing that trend is not trivial; many farmers' preference for urea is rooted in well-reasoned benefits, including flexibility, safety, and ease of use, which often outweigh some of urea's agronomic disadvantages. That said, ammonia's efficiency gains can be easily eroded by relatively minor weather variability, particularly through volatilization losses. In the near term, stabilizing current direct-application volumes is a more realistic objective than a wholesale return to anhydrous ammonia. Whether even that more modest goal is achieved depends on whether policy, technology development, and on-farm adoption can be aligned to support it — a question that extends well beyond the scope of this market analysis, but to which the data presented here provides the essential context.

APPENDIX 7: The Green Ammonia Techno-Economic Model — Description, Assumptions, and Sensitivity Analysis

Purpose and scope

The economic findings in the body of this report are produced by a deterministic techno-economic model implemented as an Excel workbook. The model computes two linked levelized costs: the Levelized Cost of Hydrogen (LCOH) from low-temperature water electrolysis, and the Levelized Cost of Ammonia (LCOA) from a conventional Haber–Bosch synthesis loop fed by that hydrogen. The two are linked through a transfer-price mechanism: the LCOH (with or without production tax credits) becomes the hydrogen feedstock price entering the ammonia model. This appendix describes the structure of those calculations, the assumptions behind the baseline case used in the body, and the sensitivity of the results to the variables that matter most. A separate user manual ships with the model and documents the workbook procedurally; this appendix focuses on conceptual structure and on the sensitivity envelope.

The model is intentionally a *screening-level* tool. It is designed to answer questions of the form "at what combination of electricity price, electrolyzer cost, and capacity factor does distributed green ammonia approach competitiveness with delivered gray ammonia into the Upper Midwest?" It is not a substitute for site-specific feasibility engineering, vendor-quote-based capital estimation, or project-finance modeling. The disclaimer reproduced at the end of this appendix sets out the limitations formally; the discussion that follows describes them substantively.

The workbook and its accompanying user manual are available for qualified research, educational, and non-commercial analytical uses on request to AURI. Requests should describe the intended use, the requesting institution, and the responsible analyst. AURI reserves the right to decline, condition, or limit access at its discretion.

System boundary and what the model does not do

The hydrogen side covers the electrolyzer system (stack, electrolyzer package, balance of plant), compression, hydrogen storage, water treatment, and all associated operating costs (electricity, water, fixed O&M, stack replacement, other variable O&M). The ammonia side covers nitrogen generation (ASU or PSA), the Haber–Bosch synthesis loop with refrigeration and separation, utilities, the minimum ammonia surge / day-tank storage required at the plant for smooth synthesis-loop operation, and an optional battery for short-term electricity buffering. Hydrogen does not appear as equipment in the ammonia model; it enters as a purchased feedstock at $/kg, which is where the transfer price plays its role. **All LCOA values reported by the model — including every value in Tables A8-6 and elsewhere in this appendix — are strictly plant-gate costs.** They reflect what it costs to produce a metric ton of anhydrous ammonia at the plant boundary, before any downstream cost is added. The model deliberately does *not* include several things that a project-level or delivered-cost analysis would:

- **Distribution from the plant gate to point of use** — pipeline tariffs, rail or truck movement, terminal handling and throughput fees, and on-farm receiving costs. These are addressed in the body of the report. For distributed plants serving a local agricultural market, the additive cost is modest, but for ammonia destined for regional terminals or export-equivalent benchmarks, the delivered-cost layer can be material.
- **Product storage beyond the plant-gate minimum.** The model includes only the minimum ammonia storage needed for synthesis-loop buffering, not the seasonal or value-chain storage that anhydrous ammonia logistics actually require. The body of the report makes clear that seasonal storage — to bridge the gap between continuous year-round production and the highly concentrated spring/fall application windows — can be a significant additional cost layer for distributed green ammonia, both in capital (large refrigerated or pressurized tanks at the plant and at regional terminals) and in carrying cost (financing inventory across the off-season). Readers comparing this appendix's LCOA values to delivered or season-adjusted ammonia prices should add a seasonal-storage allowance drawn from the body's storage-cost discussion.
- **Site-specific permitting and interconnection costs** beyond the percentage adders for installation, contingency, and owner's costs.

- **The cost of acquiring renewable electricity** beyond the wholesale-price assumption (PPA structuring fees, Renewable Energy Certificates (REC) procurement, contract-shape premiums).
- **Market premium revenues** for low-carbon attributes (LCFS credits, low-carbon premiums, environmental-attribute monetization).
- **Any tax or financing assumptions** beyond the discount rate and the optional 45V credit.

These are project-specific and would inflate the model's scope without sharpening its central question. Where comparison to a delivered gray-ammonia benchmark requires a delivered-cost layer, the body of the report supplies that layer separately; the appendix's LCOA should be read as the plant-gate floor on top of which those layers stack.

The hydrogen side: structure of the LCOH calculation

The LCOH is computed in four logical steps following the conventional levelized-cost framework used in the NREL Hydrogen Analysis (H2A) Production Models and IRENA's *Green Hydrogen Cost Reduction* methodology (NREL, 2024; IRENA, 2022). First, the electrolyzer is sized: either as a fixed nameplate (the user chooses an MW value) or to meet a target annual hydrogen production at a chosen capacity factor. The model uses the second option for the baseline, sizing the electrolyzer to deliver approximately 9,000 metric tons per year of hydrogen — the quantity needed to support a 50,000 metric-ton-per-year ammonia plant at stoichiometric ratio. Second, the electrolyzer's capital cost is composed of three line items from the technology library: stack cost, electrolyzer-package cost, and balance-of-plant cost, all expressed in $/kW. The library supports four technologies (alkaline, PEM, anion exchange membrane, and solid oxide); the baseline uses alkaline. To each line item, the model applies a CAPEX multiplier (for sensitivity) and an economy-of-scale exponent that adjusts the unit cost based on the deviation between the actual plant size and a reference size of 100 MW. The 0.85 exponent used in the baseline reflects the conventional power-law scaling range for electrolyzer modules and process equipment (Towler & Sinnott, 2022; IRENA, 2022). Compression, storage, and water-treatment CAPEX are added on top. Third, all direct CAPEX is grossed up by an installation/EPC factor (20% in the baseline), an owner's cost and permitting factor (5%), and a contingency (10%) to arrive at total installed capital. These percentages reflect mid-range industry practice for first-of-a-kind to early "nth-of-a-kind" deployments and align with the percentage-adder conventions in the National Energy Technology Laboratory's (NETL) Quality Guidelines for Energy System Studies (QGESS) and the NREL H2A workbooks (NETL, 2019; NREL, 2024). They are at the conservative end of project-developer assumptions and at the optimistic end of EPC-contractor assumptions. Fourth, the model annualizes the capital using a Capital Recovery Factor based on a 20-year project life and a 10% real discount rate, then adds annual operating costs: electricity (capacity factor × annual hours × MW × $/MWh), water and wastewater, fixed O&M as a percentage of installed capital, stack replacement annualized over the stack lifetime, and other variable O&M. The total annual cost is divided by annual hydrogen production to produce LCOH in $/kg.

The ammonia side: structure of the LCOA calculation

The ammonia model follows a different logic — it uses a net present value (NPV)-based calculation rather than a simple annualization, because the ammonia island has discrete cash-flow events (notably battery replacements at a configurable interval) that the simple-annualization approach would not handle accurately. Year-zero cash flow is the initial CAPEX outlay. Subsequent years include operating expenditure (OPEX) and ammonia production; battery replacement cash flows appear at the specified interval. The LCOA is the ammonia price at which the NPV of revenues equals the NPV of costs.

The ammonia plant CAPEX is built up by line item — inside battery limits (ISBL) costs (nitrogen generation, the HB loop, utilities, buildings and controls) and outside battery limits (OSBL) costs (site works, water treatment, loading and unloading) — at a base capacity of 100 tons per day, then scaled to the chosen nameplate (140 t/day in the baseline, equivalent to 50,000 t/year at full utilization) using power-law exponents (IEA, 2021; IRENA, 2022; KBR, 2022). Storage and battery CAPEX are added separately with their own sizing. Indirect costs (EPC, contingency, owner's) are applied as percentage adders.

OPEX on the ammonia side splits into hydrogen feedstock (the transfer price × annual H_2 consumption, where annual H_2 consumption is the stoichiometric requirement of approximately 0.176 kg H_2 per kg NH_3; Ghavam et al., 2021), electricity for ASU and the HB loop, catalyst and chemicals, other variable O&M, and fixed O&M. Of these, hydrogen is overwhelmingly dominant; in the baseline case, hydrogen feedstock accounts for approximately 80% of LCOA.

The integration and the credit toggle

The two models are linked at a single integration point: the LCOH computed on the hydrogen side becomes the hydrogen feedstock price ($/kg) entering the ammonia OPEX calculation. The Common_Assumptions sheet carries a dropdown that determines whether the unsubsidized LCOH or the credit-adjusted LCOH flows into the ammonia model. Switching this toggle is the single most important sensitivity in the entire workbook, because a $3/kg 45V production credit, applied at the hydrogen-cost level, propagates through the stoichiometric multiplier (0.176 × $3 = $0.53/kg ammonia from hydrogen alone) into a meaningful LCOA reduction. In the baseline case, switching from "Unsubsidized" to "With credits" brings LCOA from approximately $1,228/t to approximately $698/t — the credit is decisive when it applies, which is the underlying reason 45V dominates the policy discussion in the body of the report.

Baseline assumptions

The baseline case is summarized in Table A8-1. The values are drawn from publicly available literature and industry sources where available, and from conservative engineering judgment where literature is sparse or inconsistent. The *Source* column points to the primary references; full bibliographic details are in the consolidated bibliography.

Table A8-1. Baseline assumptions for the LCOH and LCOA calculations.

Parameter	Value	Source / rationale
Project life	20 years	NREL H2A convention; IEA Ammonia Technology Roadmap 2021

Parameter	Value	Source / rationale
Real discount rate	10%	NREL H2A merchant-risk convention; conservative for first-of-a-kind (IRENA, 2022)
Cost basis year	2024	Aligned with IEA *Global Hydrogen Review 2025* and DOE *Pathways to Commercial Liftoff – Clean Hydrogen*
Electrolyzer technology	Alkaline (AEL)	Lowest-cost mature technology at scale (IEA, 2025)
Electrolyzer SEC	52 kWh/kg H_2	IEA *Global Hydrogen Review 2025* / DOE / IRENA 2020 midrange for AEL
Capacity factor	30%	Renewable-paired operation midpoint (IRENA, 2022; IEA, 2025)
Electricity price	$20/MWh	Blended midpoint between curtailed-capture and contracted PPA in Upper Midwest (LBNL, 2024; LevelTen Energy, 2025)
Reference electrolyzer size	100 MW	Mid-scale modular reference (IRENA, 2022)

Parameter	**Value**	**Source / rationale**
Economy-of-scale exponent	0.85	Power-law scaling convention (Towler & Sinnott, 2022; IRENA, 2022)
Installation / EPC factor	20%	NETL QGESS; NREL H2A; conservative for FOAK / early NOAK
Owner's cost & permitting	5%	NETL QGESS; NREL H2A
Contingency	10%	NETL QGESS; AACE Class 4 screening convention
Stack life	8 years (≈ 60,000 h equivalent)	IEA *Global Hydrogen Review 2025*; DOE H2 Program record
Fixed O&M	3% of installed CAPEX	NREL H2A; DOE / IEA convention
H_2 transfer basis	Unsubsidized (default) / With credits (45V toggle)	U.S. Treasury & IRS Final 45V Regulations (2025)
NH_3 plant nameplate	140 t/day (≈ 50,000 t/year)	Sized to ≈ 1/3 of Minnesota anhydrous-ammonia demand (MDA, 2024)

Parameter	Value	Source / rationale
NH_3 turndown limit	50%	Industry-typical for fixed HB loops (IEA, 2021; KBR, 2022; Casale, 2022)
H_2 requirement (stoichiometric)	0.176 kg H_2 / kg NH_3	Chemistry; Ghavam et al. (2021)

These values are documented in the workbook's Inputs and NH3_Inputs sheets and in the References sheet that ships with the model. Where the model uses a value that is more conservative than one cited source and more optimistic than another, the choice has been made to keep the screening estimate defensible against attentive reviewers — the model is designed not to flatter the technology.

Sensitivity to electricity price

Electricity is the largest variable operating cost in green hydrogen production. Table A8-2 reproduces the LCOH response across an electricity-price sweep at the baseline 30% capacity factor and unsubsidized conditions. The same table is presented as Table 3 in the body; it is reproduced here for completeness and to anchor the discussion of the cash-cost-vs.-CAPEX (Schütz, 2018)tension that follows in Section 11.

Table A8-2. LCOH sensitivity to electricity price (alkaline, 30% CF, 20-yr project life, 10% real discount rate).

Power price ($/MWh)	**−$10**	**$0**	**$10**	**$20**	**$30**	**$40**
LCOH ($/kg)	$4.21	$4.74	$5.28	$5.81	$6.34	$6.88

Power price ($/MWh)	**−$10**	**$0**	**$10**	**$20**	**$30**	**$40**
Electricity share of LCOH	−12%	0%	10%	18%	25%	31%
Cash cost ($/kg, excl. CAPEX recovery)	$0.99	$1.53	$2.08	$2.59	$3.13	$3.6

Two observations are central. First, electricity moves the LCOH meaningfully but not dramatically: doubling the electricity price from $10 to $40/MWh raises LCOH by less than 30%, because CAPEX dominates at low utilization. Second, even at zero electricity price — a counterfactual representing fully captured curtailed power with no other cost — LCOH is still $4.74/kg, almost entirely CAPEX ecovery. Electricity alone cannot solve the cost problem.

Sensitivity to curtailed and blended electricity supply

The baseline case uses a single $20/MWh price as a midpoint estimate for electricity delivered to the electrolyzer. In practice, a distributed green ammonia plant in a high-VRE corridor will likely procure power from multiple sources: long-term contracted renewable supply (PPA, typical range $25–$40/MWh in current Upper Midwest markets per the LBNL 2024 *Land-Based Wind Market Report* and the LevelTen Energy *PPA Price Index*), short-term wholesale purchases at locational marginal price (LMP), and — where siting and interconnection allow — opportunistic capture of curtailed energy at very low or negative prices (see Appendix 2 for the discussion of MISO curtailment dynamics). The blended cost depends on the mix.

To bracket the curtailment case, Table A8-3 presents three scenarios that map directly onto the curtailment discussion in Appendix 2.

Table A8-3. LCOH sensitivity to blended electricity procurement scenarios (alkaline, 30% CF baseline).

Scenario	Blended electricity price ($/MWh)	LCOH ($/kg)	Notes
Full PPA, no curtailment capture	$30	$6.34	Reflects current Upper Midwest wind PPA range
Baseline blended	$20	$5.81	Mix of PPA and lower-cost wholesale; reference case for body
Significant curtailment capture	$10	$5.28	Roughly 30–40% of hours from curtailed power at $0–$5/MWh, rest from PPA
Heavy curtailment, partial PPA	$0	$4.74	More aggressive curtailment capture; requires careful siting in a binding-constraint corridor
Fully curtailed	−$10	$4.21	Theoretical bound; represents negative-LMP capture with no cost offset

Two important caveats apply. First, the blended price assumes that the plant can operate at the baseline 30% capacity factor regardless of curtailment availability. In practice, exclusive reliance on curtailed power would materially reduce capacity factor (since curtailment events do not align with the 30% target operating profile), pushing LCOH higher through the CAPEX-per-kg channel. The plant must either accept lower utilization or supplement curtailed hours with firm renewable power — both of which raise the *blended* electricity cost above the curtailment-only LMP. Section 8 addresses the capacity-factor sensitivity directly.

Second, the curtailment-driven cases (right-hand columns) become more attractive when paired with electrolyzer cost reductions and improved utilization. The combined-lever discussion in Section 10 returns to the curtailment case explicitly.

The directional finding is clear: at full curtailment capture, the cash cost of hydrogen approaches the unsubsidized cash cost of natural-gas-based gray hydrogen at current Henry Hub prices ($1–$2/kg). The levelized cost, however, remains substantially above gray because CAPEX still has to be recovered. This is the central tension the appendix continues to develop.

Sensitivity to capacity factor

Capacity factor is the single most punitive variable in the model, because the hydrogen plant is capital-heavy and underutilization spreads the same capital cost over fewer kilograms of output. Table A8-4 reproduces the body's Table 5 with an extension to higher utilization values that are not realistic for a renewable-paired plant but are useful as bounding conditions.

Table A8-4. LCOH sensitivity to capacity factor (alkaline, $20/MWh electricity, baseline CAPEX).

Utilization	**30%**	**50%**	**80%**	**100%**
Total project cost ($MM)	$176.4	$159.8	$107.3	$88.8
Unsubsidized LCOH ($/kg)	$5.81	$5.48	$4.03	$3.52

Utilization	30%	50%	80%	100%
CAPEX share of LCOH	55%	53%	49%	46%
Electricity share of LCOH	18%	19%	26%	29%

The capacity-factor effect is large but plateaus: doubling utilization from 30% to 80% drops LCOH by approximately 30%. Beyond 80%, gains attenuate because the dominant cost shifts from capital to electricity, and electricity is not free. Importantly, *increasing capacity factor is not generally available as a project-level lever* for a renewable-paired plant — it requires either grid-supplemented electricity (which raises the blended price and partially offsets the CAPEX saving) or operating at lower utilization deliberately to chase curtailment hours (which preserves the cheap electricity but worsens the capacity-factor problem). This coupling is the central project-design tradeoff for distributed green ammonia and is discussed further in Appendix 2.

Sensitivity to electrolyzer CAPEX

The most consequential lever over the medium term is the cost of the electrolyzer itself. Table A8-5 reproduces the body's Table 6 and shows the LCOH response across a range of CAPEX-reduction scenarios, holding electricity and capacity factor at baseline.

Table A8-5. LCOH sensitivity to electrolyzer CAPEX reduction (alkaline, $20/MWh, 30% CF).

CAPEX reduction from baseline	0%	25%	50%	70%
LCOH ($/kg)	$5.81	$4.67	$3.52	$2.60

CAPEX reduction from baseline	0%	25%	50%	70%
Electricity share of LCOH	18%	23%	30%	41%
Total project cost ($/kW)	$1,384	$1,047	$711	$411

CAPEX reductions of 50% bring LCOH to $3.52/kg, comparable to recent best-in-class Chinese alkaline systems — the IEA *Global Hydrogen Review 2025* reports Chinese installed costs in the range USD 600–1,200/kW versus USD 2,000–2,600/kW outside China (IEA, 2025). A 70% reduction approaches gray hydrogen production cost. These reductions are not engineering optimism; they are the level of cost decline that wind and solar achieved over comparable industry-scale-up windows (IRENA, 2022; DOE, 2023). Whether the green hydrogen industry will follow the same learning trajectory at the same pace remains the central uncertainty in distributed green ammonia economics.

Combined-lever scenarios

No single lever closes the gap to incumbent gray ammonia. Table A8-6 presents combined-lever scenarios that bracket the competitiveness question. **All LCOA values are plant-gate** (per Section 2); the comparison to *delivered* Upper Midwest gray ammonia discussed in the body of the report requires adding distribution and seasonal-storage layers to these values.

Table A8-6. Combined-lever LCOA scenarios (50,000 t/year alkaline plant, plant-gate, unsubsidized unless noted).

Scenario	Electricity ($/MWh)	Electrolyzer CAPEX	Utilization	LCOA ($/t NH_3)
Baseline	$20	0% reduction	30%	$1,228
Cheap power only	$10	0% reduction	30%	≈ $1,140
Capex reduction only	$20	50% reduction	30%	≈ $940
Higher utilization only	$20	0% reduction	80%	≈ $950
Curtailment + utilization	$0	0% reduction	50%	≈ $900
Combined competitive case	$10	50% reduction	50%	$750–$800
Gray-parity case	$0	70% reduction	60%	≈ $550
Baseline + 45V $3/kg credit	$20	0% reduction	30%	$698

The "combined competitive case" — the scenario in which distributed green ammonia, on a *plant-gate* basis, approaches the *plant-gate* cost of incumbent gray without production credits — requires every lever pulled meaningfully in the same direction. None of the single-lever cases is sufficient. The 45V case, for comparison, achieves plant-gate competitiveness solely through the credit, but is contingent on policy that the OBBB has materially narrowed. Whether distributed green ammonia is competitive on a *delivered* basis with delivered Upper Midwest gray depends additionally on the distribution and seasonal-storage cost gap discussed in the body of the report — a gap that can plausibly favor the distributed plant (shorter delivery legs, avoided long-haul rail / pipeline / barge) or work against it (sub-scale storage and handling at the local plant), depending on siting and offtake arrangements. The "gray-parity case" is presented for boundary illustration only: at $0/MWh electricity, 70% CAPEX reduction, and 60% utilization, green plant-gate LCOA approaches the cash cost of incumbent gray ammonia at the Gulf Coast plant gate — a plant-gate-to-plant-gate comparison. None of those input values is implausible in the medium term — gray-parity is achievable in principle, but achieving the right combination simultaneously is the unresolved structural problem.

The cash-cost vs. CAPEX tension, made explicit

The model surfaces a structural property of distributed green ammonia that warrants explicit treatment, because it is not always visible in the headline numbers. The cash cost of hydrogen — the operating cost excluding capital recovery — is highly sensitive to electricity price and can become extremely low at zero or negative power prices. Table A8-2 shows the cash cost falling to $0.99/kg at −$10/MWh and $1.53/kg at zero. At those cash costs, hydrogen-to-ammonia is competitive with steam-methane-reformed gray hydrogen on a marginal basis. The levelized cost, by contrast, includes capital recovery and is dominated by it. At 30% capacity factor, CAPEX contributes more than half of LCOH at every electricity price in Table A8-2 (consistent with the cost-structure decomposition in NREL H2A and IRENA 2020). The implication is that a green ammonia project can present a compelling cash-flow story to a buyer or to an operator while being uneconomic on a full-cost basis. This is the gap that early-mover projects must close, and it is why capital-side support — investment tax credits, grants, loan guarantees, credit enhancements — is structurally more important than production-side credits for the first wave of projects. Production credits help the cash side, which is already the strong side; investment-side support (alleviates?) the binding constraint directly.

Limitations

The reported LCOA is plant-gate only. As described in Section 2, the model captures only the minimum ammonia day-tank / surge storage required for synthesis-loop operation. It does not include distribution costs from the plant gate to the point of use, nor does it include seasonal or value-chain ammonia storage — both of which the body of the report identifies as potentially significant additional cost layers for distributed green ammonia projects. Users comparing the appendix LCOA values to delivered, retail, or seasonally adjusted ammonia prices must add those layers from outside the model. The model assumes the ammonia synthesis loop operates at 100% utilization, buffered by hydrogen storage on the upstream side. A more sophisticated treatment would model the ammonia loop as variable-load, capturing the developing class of flexible HB technologies (Casale, KBR, Topsoe, ThyssenKrupp Uhde). The Simplified_Storage sheet uses the 100%-loop assumption; the H2_Storage sheet provides a block-by-block alternative but is not used in the baseline. The model does not include market-side revenues beyond the levelized ammonia price. Specifically, it does not model carbon-intensity premiums, low-carbon-fuel-standard (LCFS) credits , 45Q for biogenic CO_2 pathways, or any other environmental-attribute monetization. These could materially improve project economics but are jurisdiction- and offtaker-specific. The model does not include the cost or revenue implications of grid services that a flexible electrolyzer load could provide (frequency response, demand response, capacity payments). These can be material in certain market structures and are an active area of analysis that this screening tool does not capture. Finally, the model uses the published 45VH2-GREET emissions tiers as a binary credit eligibility input; it does not compute the lifecycle emissions itself. Eligibility for the top 45V tier (and therefore the $3/kg credit value used in subsidized scenarios) is contingent on the four pillars discussed in Appendix 3 and cannot be assumed for any specific project without independent lifecycle accounting.

Disclaimer

The results of this model are provided by AURI solely as a research and educational tool. The model is intended to support preliminary techno-economic screening of green hydrogen and green ammonia production concepts and is not intended to serve as, nor should it be relied upon as, a substitute for independent engineering analysis, professional feasibility studies, or formal investment appraisal. AURI makes no representations or warranties, express or implied, regarding the accuracy, completeness, reliability, or suitability of the model, its outputs, or the data contained herein for any particular purpose. Default input values, technology parameters, cost data, and assumptions embedded in this model are drawn from publicly available literature and are provided for illustrative purposes only. They may not reflect current market conditions, site-specific factors, or vendor-specific pricing. Users are solely responsible for verifying all inputs, assumptions, and outputs against independent sources before relying on any results.

Data Sources for model development:

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- **IRENA (International Renewable Energy Agency).** (2020, December). *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal.* Abu Dhabi. https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction — *Primary source for the electrolyzer power-law scaling convention, the 100 MW reference size, the merchant-risk discount-rate convention, and the FOAK-vs-NOAK cost decomposition.*

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APPENDIX 8: Glossary of Terms and Definitions

Fertilizer and Nitrogen Products

AA – Anhydrous Ammonia [NH3]. 82% N. AA is a liquid form of nitrogen when under pressure and turns into a gas when released, making it more dangerous to handle and requiring appropriate permits for storage and transport. If a crop requires 100 lbs/acre of nitrogen, AA is injected into the soil and applied at a rate of 122 lbs/acre.

Ammonia volatilization: the process by which nitrogen in the form of urea or ammonium escapes from soil into the atmosphere as ammonia gas, leading to nitrogen loss from soils.

Biologicals (also referred to as biostimulants or biocatalysts) – In soil management, biologicals refer to products that contain beneficial, naturally occurring microorganisms or microbial derivatives that can aid in nutrient use efficiency and enhance the overall soil health ecosystem (University of Illinois Urbana-Champaign, 2023).

DAP – Diammonium Phosphate. Composed of 18% nitrogen and 46% phosphorus, DAP is applied at a rate of 50-200 lbs/acre and is more suitable for acidic soils and during a crop's early growth stages. DAP is more soluble in water, allowing for quicker absorption by plants than MAP, but it can lead to ammonia volatilization.

MAP – Monoammonium Phosphate. Composed of 11% nitrogen and 52% phosphorus, MAP is applied at a rate of 50-200 lbs/acre and is more suitable for alkaline and phosphorus-deficient soils. MAP is less water-soluble and absorbs less moisture from the air but enhances micronutrient availability.

UAN – Urea-ammonium nitrate. 28% or 32% N.

Urea [CO(NH2)2] – 46% N. If a crop requires 100 lbs/acre of nitrogen, urea is spread on the soil's surface and applied at a rate of 217 lbs/acre. To avoid ammonia volatilization, best management practices include incorporating it into the soil within three-four days of application, either by tillage or rainfall (typically requiring ¼ to ½ inches of rain).

Ammonia and Hydrogen Production (Technical and Process)

AEL – Alkaline Electrolysis. The most mature water-electrolysis technology for producing hydrogen.

AEM – Anion Exchange Membrane. An emerging electrolyzer type combining features of alkaline and PEM systems.

ASU – Air Separation Unit. Equipment that isolates nitrogen from air as a feedstock for ammonia synthesis.

ATR – Autothermal Reforming. A natural-gas reforming route to hydrogen, lower-carbon than conventional SMR when paired with carbon capture.

BoP – Balance of Plant. The supporting equipment and systems surrounding the core process units.

CCS – Carbon Capture and Storage. Capturing CO2 emissions and storing them underground.

CCU – Carbon Capture and Utilization. Capturing CO2 for use as a feedstock rather than storing it.

CCUS – Carbon Capture, Utilization, and Storage. The combined family of CO2 capture, use, and storage technologies.

DGA – Distributed Green Ammonia. Small- to medium-scale green ammonia produced near the point of use.

HB – Haber–Bosch. The industrial process that synthesizes ammonia from hydrogen and nitrogen.

ISBL – Inside Battery Limits. Capital costs of the core process units within the plant boundary.

OSBL – Outside Battery Limits. Capital costs of supporting infrastructure outside the core process units.

P2A – Power-to-Ammonia. Producing ammonia from renewable electricity via electrolytic hydrogen.

PEM – Proton Exchange Membrane. A water-electrolysis technology well suited to variable renewable power.

PSA – Pressure Swing Adsorption. A gas-separation method used here to generate nitrogen for ammonia synthesis.

SMR – Steam Methane Reforming. The conventional, carbon-intensive route to hydrogen from natural gas.

SOEC – Solid Oxide Electrolysis Cell. A high-temperature electrolyzer technology.

Electricity, Grid, and Renewables

LMP – Locational Marginal Price. The price of electricity at a specific grid node, reflecting congestion and losses.

Long Range Transmission Planning (LRTP): MISO process explicitly addressing future reliability and transfer needs under evolving resource portfolios.

Midcontinent Independent System Operator (MISO) – a regional transmission organization and independent system operator responsible for operating the high-voltage electric grid and administering wholesale electricity markets across a large portion of the central U.S. and Manitoba, Canada.

Variable Renewable Energy (VRE) – refers to renewable energy sources whose output naturally fluctuates because they depend on weather or seasonal conditions; the two most common forms are wind- and solar-generated energy.

Economics and Finance

CAGR – Compound Annual Growth Rate. The mean annualized growth rate over a multi-year period.

Capital Expenditures (CAPEX): the money a company spends to buy, upgrade, or maintain long-term assets, supporting growth and operational capacity. Unlike OPEX, CAPEX depreciates over time, meaning it isn't fully deducted in the year it's spent, but is spread over the useful life of the asset.

COD – Commercial Operations Date. The date on which a facility begins commercial operation.

CRF – Capital Recovery Factor. The factor that converts an upfront capital cost into an equivalent annualized cost.

Levelized Cost of Ammonia (LCOA) – to calculate the LCOA, we use LCOH as a transfer price in a production cost model that adds all the other variable and fixed costs of the ammonia plant.

Levelized Cost of Hydrogen (LCOH) – calculated assuming a 20-year project life and a 10% hurdle rate (note: hurdle rate is the minimum required rate of return that a project must earn for an investor (or company) to consider it financially worthwhile).

LCP – Levelized Cost of Production. The all-in average unit cost of output over a project's life.

NPV – Net Present Value. The present value of a project's future cash flows net of its costs.

Operating Expenditures (OPEX) – day-to-day costs of running a business that are recurring; unlike CAPEX, it does not create long-term assets and is expensed immediately.

PPA – Power Purchase Agreement. A long-term contract to buy electricity at a pre-agreed price.

Policy, Tax, and Incentives

45Q – Section 45Q Carbon Oxide Sequestration Tax Credit. A U.S. federal tax credit for capturing and sequestering CO2.

45V – Section 45V Clean Hydrogen Production Tax Credit. A U.S. federal tax credit scaled to the carbon intensity of the hydrogen produced.

Inflation Reduction Act (IRA) – U.S. law enacted in 2022 to support the widespread adoption and implementation of carbon capture technologies for decarbonization across several industries (The Industrial Distribution Experts, 2022).

IRS – Internal Revenue Service. The U.S. federal tax authority that administers the hydrogen and carbon tax credits.

One Big Beautiful Bill (OBBB) – U.S. law enacted in 2025 containing sweeping tax, spending, and policy reforms (Internal Revenue Service, 2026).

Models, Standards, and Certificates

EAC – Energy Attribute Certificate. A tradable instrument certifying the renewable attributes of a unit of electricity.

FOAK – First-of-a-Kind. A first commercial deployment of a technology, typically higher-cost.

GREET – Greenhouse gases, Regulated Emissions, and Energy use in Technologies. Argonne National Laboratory's lifecycle-emissions model used in 45V accounting.

H2A – Hydrogen Analysis. NREL's hydrogen production cost-modeling framework.

NOAK – Nth-of-a-Kind. A mature deployment following first-of-a-kind units, with lower expected costs.

QGESS – Quality Guidelines for Energy System Studies. NETL's cost-estimating guidelines for energy system studies.

REC – Renewable Energy Certificate. A certificate representing one MWh of renewable electricity generation.

Emissions, Fuels, and Shipping

CFR – Cost and Freight. An international shipping term under which the seller covers cost and freight to the destination port.

CI – Carbon Intensity. Lifecycle greenhouse-gas emissions per unit of product or energy.

FOB – Free on Board. A shipping term under which the buyer assumes cost and risk once goods are loaded.

GHG – Greenhouse Gas. Gases such as CO2 and N2O that contribute to climate warming.

GWP – Global Warming Potential. A measure of a gas's warming effect relative to CO2 over a set time horizon.

LNG – Liquefied Natural Gas. Natural gas cooled to liquid form for storage and transport.

NG – Natural Gas. The fossil feedstock for conventional ("gray") ammonia.

SAF – Sustainable Aviation Fuel. A lower-carbon jet fuel representing a potential higher-value market.

Organizations and Agencies

AURI – Agricultural Utilization Research Institute. The Minnesota nonprofit that authored this report.

DOE – U.S. Department of Energy.

EIA – U.S. Energy Information Administration. The federal statistical agency for energy data.

FAO – Food and Agriculture Organization. The United Nations agency for food and agriculture.

IEA – International Energy Agency.

IPCC – Intergovernmental Panel on Climate Change. The United Nations body for climate science assessment.

IRENA – International Renewable Energy Agency.

LBNL – Lawrence Berkeley National Laboratory. A U.S. Department of Energy national laboratory.

MDA – Minnesota Department of Agriculture.

NETL – National Energy Technology Laboratory. A U.S. Department of Energy national laboratory.

NRCS – Natural Resources Conservation Service. A USDA agency supporting on-farm conservation practices.

NREL – National Renewable Energy Laboratory. A U.S. Department of Energy national laboratory.

OSHA – Occupational Safety and Health Administration. The U.S. federal workplace-safety regulator.

RMI – Rocky Mountain Institute. An energy-research nonprofit.

UMN – University of Minnesota.

UNCTAD – United Nations Conference on Trade and Development.

USDA – U.S. Department of Agriculture.

USGS – U.S. Geological Survey. The federal agency tracking mineral and commodity data.

Units and Measures

CO2e – Carbon Dioxide Equivalent. A unit expressing the warming impact of greenhouse gases in terms of an equivalent amount of CO_2.

GW – Gigawatt. One billion watts (1,000 MW) of power capacity.

kg – Kilogram. Used here for hydrogen output and cost (e.g., $/kg H_2).

kta – Kilotons per Annum. Thousand metric tons per year of production capacity.

kV – Kilovolt. One thousand volts; used for transmission-line voltage.

kW – Kilowatt. One thousand watts; electrolyzer capital cost is often quoted in $/kW.

kWe – Kilowatt-electric. A kilowatt measured as electrical output, as distinct from thermal.

kWh – Kilowatt-hour. One kilowatt of power sustained for one hour; a unit of energy.

lbs/acre – Pounds per Acre. A fertilizer application rate.

MM – Million. Financial shorthand (e.g., $MM denotes millions of dollars).

mol – Mole. The chemistry unit of amount of substance (e.g., mol H_2 per mol NH_3).

MW – Megawatt. One million watts (1,000 kW) of power capacity.

MWh – Megawatt-hour. One megawatt sustained for one hour; electricity price is often quoted in $/MWh.

t – Metric Ton (tonne). 1,000 kilograms; used for ammonia and CO_2 quantities (e.g., t CO_2/t NH_3).

tpd – Tons per Day. A measure of plant production rate.

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