
Facts & Insights

# Pragmatic Barriers within the Dutch Borders for Ammonia Decarbonisation

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# 1. Introduction: The Dutch Nitrogen Landscape

The Netherlands sits at the absolute epicentre of the European chemical transition. Despite its small geographic footprint, the country hosts one of the most concentrated, highly optimised nitrogen asset bases in the world. As the continent (Europe as a whole) aggressively targets net-zero carbon thresholds under the European Green Deal [1] and the REPowerEU framework [2], these massive industrial hubs are facing an existential crossroad: completely overhaul the molecular foundation of their manufacturing loops or face structural obsolescence.

## 1.1. Profile of Global Assets on Dutch Soil

The Dutch nitrogen infrastructure is anchored by two massive, world-scale manufacturing complexes that collectively support over 3 million metric tons of annual ammonia ($NH_3$) production capacity.

- **Yara Sluiskil (Zeeland)**: Situated on the Ghent-Terneuzen Canal with direct deepwater access to the North Sea, the Sluiskil site is Europe's largest single-site ammonia and nitrate fertilizer complex [3]. Operating three massive ammonia plants with an aggregated capacity of **1.9 million metric tons per year,** Yara Sluiskil acts as a primary agricultural backbone for Northwestern Europe. In response to carbon pricing pressures, Yara has commercialized its landmark cross-border carbon capture and storage (CCS) partnership with Norway's Northern Lights [4], designed to liquefy and export up to 800,000 tons of $CO_2$ annually.

- **OCI Nitrogen / AGROFERT (Chemelot Cluster, Geleen)**: Located deep inland within the landlocked province of Limburg, the Chemelot industrial park hosts the former OCI Nitrogen asset base. Operating two highly integrated ammonia synthesis units with a combined capacity of **1.2 million metric tons per year** (with downstream capabilities matching 1.45 million tons of finished nitrate fertiliser), this facility forms the chemical core of the region's melamine and fertilizer supply chains. Reflecting the immense economic strain of European energy costs, OCI Global finalised an agreement to divest a 50% controlling equity stake of this nitrogen footprint to Central European industrial giant AGROFERT [5], passing operational steering of the asset to a regional strategic specialist.

## 1.2. The Conventional Baseline

To appreciate the scale of the decarbonisation challenge, we must first establish the conventional fossil-fuel baseline that governs these facilities. Under standard configurations, both Yara Sluiskil and the Chemelot site utilise the conventional **Steam Methane Reforming (SMR)** pathway.

In this process, natural gas ($CH_4$ ) serves a dual role: it is combusted to generate the extreme high-temperature heat required for the cracking ovens, and it acts as the primary chemical feedstock, stripped of its hydrogen atoms to react with atmospheric nitrogen ($N_2$).

**The Carbon Math**: For every metric ton of ammonia synthesized via standard SMR, approximately 1.83 tons of $CO_2$ are generated as an inescapable byproduct. This dual-use total is divided between chemical process stripping (~55-60%) and furnace combustion fuel (~40-45%) [6].

When running at 100% nameplate capacity, the combined operations of Yara and OCI pull in roughly **2.77 billion cubic meters (bcm) of natural gas per year**, resulting in a direct Scope 1 emissions footprint of **5.68 million metric tons of CO2 annually**. This single chemical sub-sector accounts for a substantial percentage of total Dutch industrial greenhouse gas emissions.

## 1.3. Scope of the Report

The objective of this report is to systematically deconstruct the practical boundaries that govern the transition of these two specific assets away from fossil natural gas. While standard political narratives advocate for the immediate, wholesale replacement of SMR with green hydrogen electrolyzers, this document maps out the hard physical, logistical, and geographical realities inside the Dutch border.

By analysing the strict caps on domestic bio-methane production, the severe bottlenecks within the North Sea offshore wind buildout, and the intense cross-sector competition for green molecules, this report establishes why a pure, single-technology solution is a mathematical impossibility. Instead, it provides a data-driven blueprint for a domestic hybrid architecture capable of keeping the Dutch chemical sector viable without starving the broader economy of clean energy.

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# 2. The Feedstock Appetite: Mapping the Gas & Energy Demands

One needs to dive deep into chemical thermodynamics in order to understand how ammonia production can be decarbonised. The transition from natural gas to electricity (for green hydrogen) is not a simple swap of power sources. It is a fundamental shift in how one manipulates matter at the molecular level.

## 2.1. SMR process thermodynamics: Why Ammonia demands methane?

To understand why conventional ammonia production is so locked into natural gas, we have to look at the chemistry of the Steam Methane Reforming (SMR) process. The Haber-Bosch reaction itself is straightforward:

$$N_2 + 3H_2 \rightleftharpoons 2NH_3 \; (\Delta H^o = -92.4 \text{ kJ/mol})$$

While atmospheric nitrogen ($N_2$) is abundant, harvesting the hydrogen ($H_2$) is the core challenge. SMR achieves this by cracking the hydrogen atoms off methane ($CH_4$) in a two-stage thermodynamic process:

**The Primary Reforming Stage**: Methane and superheated steam are passed over a nickel catalyst inside reformer tubes. This reaction is highly endothermic (it absorbs heat) and operates at punishing temperatures between 700 $^oC$ and 1000 $^oC$ [1]. To maintain these extreme temperatures, a massive portion of natural gas must be burned in the reformer's furnace burners to supply the necessary thermal energy.

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2 \; (\Delta H^o = +206 \text{ kJ/mol})$$

**The Water-Gas shift Stage**: The carbon monoxide (CO) byproduct is reacted with more steam to squeeze out a final mole of hydrogen:

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \; (\Delta H^o = -41 \text{ kJ/mol})$$

This highly integrated process is thermodynamically optimised. Modern SMR plants are built as giant waste-heat recovery networks. The heat from the furnace flue gas and the hot process gas is recycled to generate high-pressure steam, which in turn drives the turbine compressors that pressurise the Haber-

Bosch loop to over 150 bar. Because of this extreme thermal integration, an SMR plant cannot simply be "turned down" or run intermittently without risking severe thermal stress and catalyst damage.

## 2.2. Aggregated Asset Matrix: Natural Gas Consumption

To convert these chemical realities into hard volumes, the current fuel and feedstock appetite of the Dutch ammonia fleet needs to be analysed. Modern SMR assets operate near the thermodynamic Best Available Technology (BAT) limit, consuming an average specific energy input of **32 Gigajoules (GJ)** [2] **per metric ton of ammonia produced (LHV basis)**.

Since one cubic meter of pipeline-quality methane has an energy density of approximately **35.8 Megajoules (MJ)** [3], a world-class European plant requires **894 cubic meters ($m^3$) of gas per ton of synthesised ammonia.**

Using this conversion baseline, the table below maps the annual natural gas appetite of Yara Sluiskil and OCI Nitrogen at full operational capacity:

| Manufacturing site | Annual Ammonia Capacity (metric tons) | Specific Gas consumption ($m^3$/ton of $NH_3$) | Annual methane demand (billion cubic meters - bcm/year) |
|---|---|---|---|
| Yara Sluiskil | 19,00,000 | 894 | 1.7 |
| OCI Nitrogen (Chemelot) | 12,00,000 | 894 | 1.07 |
| Aggregated Dutch fleet | 31,00,000 | 894 | 2.77 |

Keeping these two industrial clusters running at full capacity requires a continuous, year round supply of **2.77 billion cubic meters (bcm) of methane annually**.

## 2.3. The Electricity Requirement: The Green hydrogen Footprint

A complete swap of natural gas with hydrogen from water electrolysis entails splitting water into its basic elements - hydrogen and oxygen. Water splitting is far more energy-intensive than methane steam reforming because water molecules are highly stable. When aggregating the total electric power required to run the low-temperature water electrolyser (Alkaline or Proton Exchange Membrane), the cryogenic Air Separation Unit (ASU) that captures pure nitrogen, and the massive mechanical compressors needed for the Haber-Bosch loop, the specific energy consumption is **10.5 Megawatt-hours (MWh)** [4] **of electricity per metric ton of green ammonia**.

To transition the entire 3.1 million metric ton Dutch ammonia fleet to a 100% electrified pathway, the annual electricity demand is:

3.1 million metric tons $NH_3$ x 10.5 MWh/ton = 32.55 TWh

The above number is close to the figure quoted (29.6 TWh) in an earlier report [5] published by VenkaCon Consulting back in 2024.

To put 32.55 TWh into perspective: this is equivalent to roughly **27% of the total annual electricity consumption of the entire Netherlands**. Replacing the feedstock for just these two chemical hubs via a pure green hydrogen pathway would require nearly a third of the country's current national power generation.

# References

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[2] https://www.iea.org/reports/ammonia-technology-roadmap/executive-summary

[3] https://en.wikipedia.org/wiki/Energy_density

[4] https://www.e3s-conferences.org/articles/e3sconf/abs/2025/01/e3sconf_icegc2024_00065/e3sconf_icegc2024_00065.html

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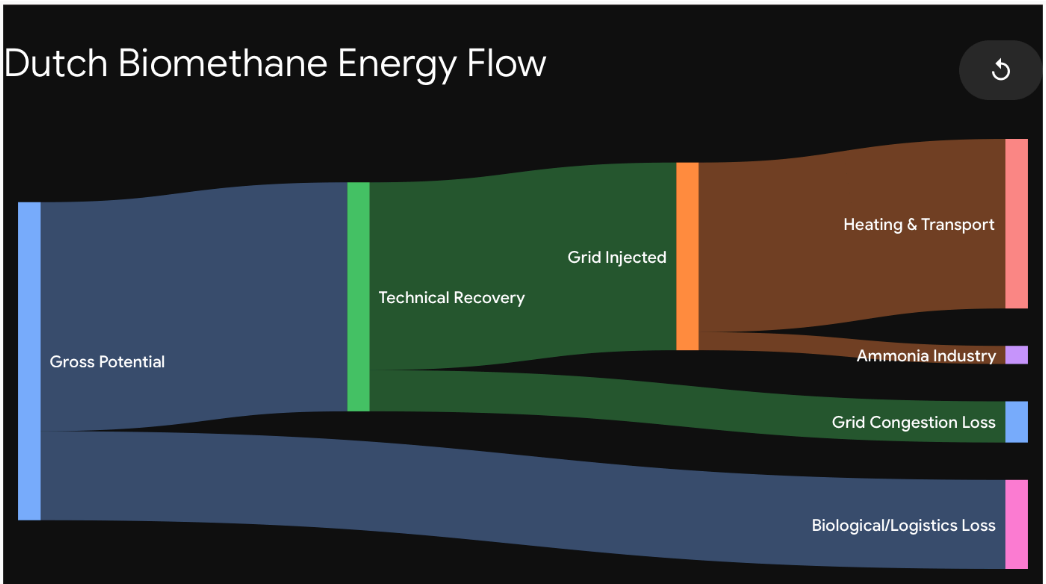
# 3. The Bio-methane Vector: Technical Realities & Feedstock Caps

While utilising bio-methane as a drop-in biogenic feedstock offers an elegant, zero retrofit decarbonisation pathway for existing Steam Methane Reforming (SMR) plants, it is governed by hard biophysical limits. Transitioning from the theoretical potential of organic matter decay to the practical delivery of grid-ready, upgraded bio-methane reveals a rigid supply ceiling.

## 3.1. The 1.8 bcm per year Ceiling

In policy documents and macro-energy models, the potential of green gas (bio-methane) is frequently overstated by assuming frictionless collection and 100% conversion of all available organic matter. However, rigorous techno-economic assessments conducted by **CE Delft and the New Energy Coalition** paint a more grounded picture for the 2030 horizon [1].




| Flow Stage | Volume (bcm) | Status |
|---|---|---|
| Gross Biological Potential | 3.00 | Source |
| Technically Collectable | 2.16 | Process |
| Practical Grid-Injected | 1.77 | Available |
| Ammonia Industry Remainder | 0.17 | Final Use |

While the gross theoretical biological potential of all Dutch organic waste exceeds 3.0 bcm/year, **the practical techno-economic ceiling is capped at 1.8 bcm/year**. This 1.8 bcm/year limit represents what can realistically be harvested, upgraded to natural gas pipeline specifications, and injected into the national high-pressure grid managed by Gasunie under aggressive capital subsidy support (such as Dutch SDE ++ scheme).

## 3.2. Stream Segmentation: Manure vs Secondary Biogenic Waste

In order to understand the logistics of this 1.8 bcm/year cap, one must segment the biogenic streams based on their chemical origin and conversion technologies. The total practical volume is divided into two distinct feedstocks and given in the Table below.

Mono-manure digestion is highly prized because it prevents raw manure from releasing fugitive methane ($CH_4$) and nitrous oxide ($N_2O$) emissions directly into the atmosphere during farm storage.

| Feedstock Stream | Annual Practical Yield (till 2030) | Primary Technology | Technical and Operational Profile |
|---|---|---|---|
| Livestock Manure | 1.0 bcm/year | Mono-Manure Anaerobic Digestion (Monomestvergisting) | Relies strictly on animal slurry (cattle, pig, and poultry). Yields a clean, consistent biogas but has a low carbon density per ton of wet slurry, requiring massive volumetric handling. |
| Secondary Biogenic Waste & Gasification | 0.8 bcm/year | Co-digestion, Sewage Sludge Treatment & Thermal Gasification | Utilises sewage sludge, municipal food waste, crop residues, and woody biomass. Pushing to the 0.8 bam mark relies heavily on scaling high-temperature biogenic gasification. |
| Total Practical Pool | 1.8 bcm/year | | |

According to **IEA Bioenergy Task 37**, wet dairy cattle slurry yields only **15 to 25 $m^3$ of raw biogas per metric ton** of fresh mass [2]. In contrast, dry food waste yields **150 to 200 $m^3$ of biogas per ton** due to its high dry matter and volatile solids content [3].

This difference creates a massive handling challenge: because raw agricultural biogas is only ~57% (on average) pure methane, producing 1.0 bcm of pure, upgraded bio-methane requires roughly 1.75 bcm of raw biogas.

If the Dutch agricultural sector processed pure, low-yield wet cow manure (20 to 25 $m^3$ biogas/ton), it would have to physically collect, transport, and digest **70 to 88 million metric tons** of fresh slurry per year. To bring this mass down to a manageable **35 to 40 million metric tons**, the sector must digest highly optimized manure mixes - combining dry poultry bedding and pig slurry- to push the average yield to a higher baseline of 45 to 50 $m^3$ of biogas per ton of digested mass.

## 3.3. Logistics and Infrastructure Obstacles

Translating this biogenic potential into a continuous feedstock stream for industrial-scale ammonia synthesis loops introduces three severe logistical bottlenecks:

- <u>Farm-level scale and financial viability</u>

  To upgrade raw biogas (which is roughly 55-60% $CH_4$ and 40% $CO_2$) into grid-ready bio-methane (minimum 90% $CH_4$ under Dutch low-calorific “G-gas” specs), which requires a specific Wobbe Index of 43.7 to 44.4 MJ/$m^3$, a farmer must install a gas-upgrading unit [4].

  Technology assessments by the **European Biogas Association (EBA)** place the capital expenditure of an industrial membrane-separation upgrading unit at € 0.5 to € 0.8 million [5]. To amortise this capital cost, a farm must have a minimum steady baseline of 350 to 400 dairy cows generating over 10,000 $m^3$ of fresh manure slurry annually. However, statistics from **ZuivelNL and Statistics Netherlands (CBS)** show the average Dutch dairy farm hosts roughly 100 to 110 cows [6]. The vast majority of agricultural holdings are structurally too small to support standalone upgrading units.

- <u>Regional biogas clustering</u>

  To bypass the scale bottleneck, the Dutch agricultural transition relies on **regional biogas clustering**. In this setup:

- Dozens of small, decentralised farms install simple, low-cost anaerobic digesters on their own yards.
- The raw, low-pressure biogas is transported through local, low-pressure PVC pipe networks to a centralised shared upgrading facility.
- This central hub strips out the $CO_2$ and $H_2S$, odorizes the gas, and injects the high-purity biome thane into a regional Gasunie pipeline.

While elegant on paper, constructing these rural pipeline webs requires complex environmental permitting, crossing private land deeds, and negotiating multi-party cooperative agreements, which typically results in **project lead times of 5 to 7 years** [7].

- High-Voltage grid congestion (*Netcongestie*)

Even if the gas upgrading is successful, the centralized upgrading hubs require electrical power to run their high-pressure compressors.

Under the severe grid congestion (Netcongestie) currently plaguing Dutch provinces like North Brabant, Gelderland, and Overijssel, high-voltage operator TenneT and regional operators (like Liander and Enexis) are routinely refusing new grid-connection requests for industrial compressors [8]. Biogas plants are being built but left idle because they cannot secure the electrical capacity to compress and inject their bio-methane into the national gas grid.

# References

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[2] **IEA Bioenergy Task 37**: *Biogas Country Reports, section on typical agricultural slurry biogas yields*.

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[8] **TenneT / Netbeheer Nederland**: National Capacity and Congestion Management Interactive Maps (2024-2026 data). https://www.netbeheernederland.nl/netcapaciteit-en-flexibiliteit/capaciteitskaart

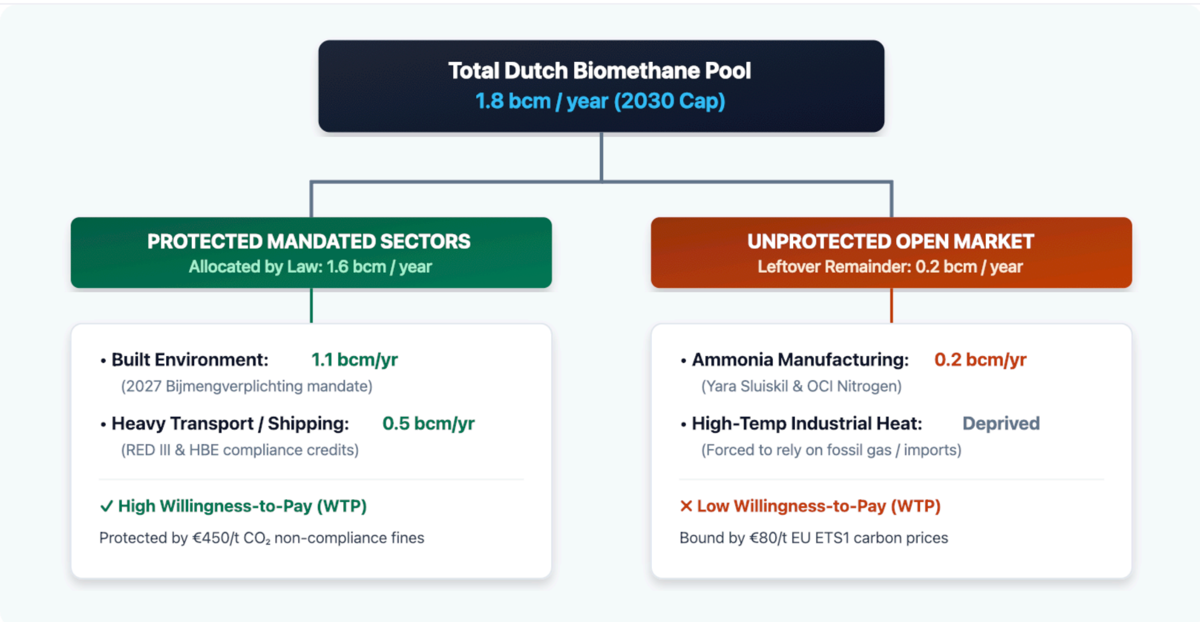
# 4. Cross-Sector Competition

Introducing biogenic carbon into a closed national energy system does not magically erase emissions. Instead, it triggers a zero-sum carbon shell game. Because the domestic pool of upgraded bio-methane is physically capped at 1.8 bcm/year, any regulatory mechanism that secures a green molecule for one sector systematically deprives another, forcing the losing sector to rely on fossil-based alternatives.

This section deconstructs the regulatory and economic matrix that governs how this 1.8 bcm pool is carved up, exposing why the ammonia industry is structurally positioned to lose the open-market bidding war.

## 4.1. The Regulatory Priority Matrix (Bijmengverplichting Groen Gas)

The distribution of green gas in the Netherlands is not driven by free-market thermodynamics. It is dictated by strict legislative mandates. The primary driver of this allocation is the Dutch **Bijmengverplichting Groen Gas (Green Gas Blending Obligation)**, which was officially finalised in the 2025 Dutch Klimaatnota to take effect on January 1, 2027 [1,2].



The allocation of the 1.8 bcm/year to different sectors is shown in the figure above.

Under this mandate, gas suppliers delivering to the built environment (residential and commercial space heating) are legally required to demonstrate that an annually increasing percentage of their gas portfolio consists of certified biogenic gas. The policy targets a domestic grid injection of 1.1 bcm/year of green gas by 2030 [3].

Crucially, this law is specifically designed to decarbonise the built environment. Heavy chemical processes, such as steam methane reforming for ammonia, are explicitly excluded from the mandate. This regulatory ring-fencing shields domestic consumers from the carbon tax but effectively starves the chemical feedstock market of affordable biogenic molecules.

## 4.2. Competitor Mechanics: Who controls the molecules?

To understand how Yara and OCI Nitrogen are priced out of the market, one must analyse the "Willingness-to-Pay" (WTP) of the three primary competing sectors. This WTP is directly linked to the specific carbon penalties each sector faces.

- <u>The Built Environment (Heating Utilities)</u>

The 2027 Bijmengverplichting is enforced by the Dutch Emissions Authority (NEa) via tradable **Green Gas Units (GGEs)** [4]. To make matters more urgent, the European Union's new **ETS2** system is scheduled to launch on **1 January 2028**, forcing gas suppliers to buy emission allowances for the heating fuels they deliver [5].

The penalty for failing to meet the annual blending quota is tied to an implied carbon price of approximately **€450 per metric ton of avoided $CO_2$** [6].

As the penalty is so high, utility giants like Vattenfall, Essent etc. can easily pass these compliance costs onto millions of retail consumers. This gives them a massive, subsidised WTP of up to €2.5 per cubic meter of upgraded biogenic gas.

- Heavy Transport & Maritime Shipping (Bio-LNG)

This sector is governed by the European Union's **Renewable Energy Directive (RED III)** and the **ReFuelEU Maritime** initiatives. Under Dutch law, injecting bio-methane into transport vehicles generates lucrative compliance credits known as **HBEs (Henieuwbare Brandstofeenheden)**. Shipping lines and long-haul logistics companies face severe, escalating fines if they do not displace heavy fuel oils and diesel.

The HBE trading market frequently values biogenic transport fuel at equivalent carbon prices exceeding **€250 to €300 per metric ton of $CO_2$**. As shipping companies must run their dual-fuel LNG engines on bio-LNG to comply, they actively outbid industrial players on the open market, locking down roughly 0.5 bcm/year of the available pool.

Note: The HBE is an energy-based certificate. The price mentioned above is a rough conversion from the amount of renewable energy used and kg $CO_2$ saved and this number is bound to change year on year.

- The Ammonia Industry (Chemical Feedstock)

Unlike heating and transport, the ammonia industry is exposed to the classic **EU ETS1 (Emission Trading System)**. Chemical plants must purchase ETS1 allowances for their direct emissions. While ETS1 prices are a significant operational burden, they typically hover around **€60 to €80 per metric ton of $CO_2$** [7].

Now, since the carbon penalty in ETS1 (€80/ton) is a fraction of the penalty in the built environment (€450/ton) and transport, the economic value of a green molecule to YARA or OCI is structurally capped. If Yara attempts to buy bio-methane at utility prices (€2.50/$m^3$), the resulting "green ammonia" would cost over €2,500 per ton to produce. Since conventional ammonia trades globally between €400 and €600 per ton [8], paying such a premium would lead to immediate corporate insolvency.

## 4.3. Carbon Abatement Efficiency Analysis

From a systemic engineering standpoint, the Dutch allocation policy represents a severe efficiency paradox. Due to the fact that different fossil fuels carry different chemical energy densities and carbon loads, a single cubic meter of biogenic methane (bio-methane) achieves a different carbon-abatement 'leverage' depending on which fossil fuel it displaces:

$$\text{Carbon Leverage}\left(\frac{\text{Mton } CO_2}{\text{bcm}}\right) = \frac{\text{Emissions of Displaced Fossil Fuel (Mton)}}{\text{Energy Equivalent Biomethane Volume (bcm)}}$$

To maintain accounting consistency across all demand sectors, gross carbon abatement calculations are evaluated at the energy input boundary when carrying out fuel replacement.

| Target Allocation Sector | Displaced Fossil Fuel | Specific Carbon Intensity of displaced fuel | Net Systemic $CO_2$ saved per 1.0 bcm shift | Abatement Efficiency Rank |
|---|---|---|---|---|
| Heavy Transport & Shipping | Heavy marine Fuel Oil/Diesel | ~74 g $CO_2$/MJ | 2.65 Million Tons | 1st (Most Efficient) |
| Ammonia Manufacturing | Natural Gas (Process SMR + Furnace) | ~56 g $CO_2$/MJ + process $CO_2$ | 2.05 Million Tons | 2nd |
| Built Environment (Heating) | Grid Natural Gas (Boiler Combustion) | ~56 g $CO_2$/MJ | 2.008 Million Tons | 3rd (Least Efficient) |

The Table above calculates the net systemic carbon-reduction leverage of routing 1.0 bcm of bio-methane to each of the three competing sectors.

Note: The detailed calculations mentioned in the above Table are given in Appendix 1.

## 4.4. The Allocation Paradox

The carbon math done above exposes a glaring conflict between political expediency and thermodynamic reality.

**The Paradox**: The Dutch regulatory framework (the 2027 Bijmengverplichting) mandates that the lion's share of bio-methane (1.1 bcm) must be allocated to the Built Environment - the very sector that yields the lowest carbon reduction per cubic meter (2.008 Mton $CO_2$ /bcm) and has the scope to be electrified with Heat Pumps (offering a COP of ~3.5). Conversely, the Ammonia Industry, which can achieve a slightly higher carbon abatement return (2.05 Mton $CO_2$ /bcm) due to eliminating chemical process emissions, is left with the leftover crumbs.

From a system-wide decarbonisation perspective, **bio-methane ($CH_4$) provides the highest macro-environmental value** when replacing fossil methane in **applications that cannot be electrified** - specifically chemical feedstocks like ammonia ($NH_3$). Because penalty structures in the built environment (€450/ton $CO_2$e) dwarf the industrial carbon price under ETS1

(€80/ton $CO_2e$), the market force funnels 89% of the available bio-methane into sectors where superior electric alternatives exist, leaving hard-to-abate industries reliant on fossil natural gas.

This zero-sum bottleneck confirms that without a major policy correction, the Dutch domestic bio-methane pool cannot save the ammonia sector. It forces the industry to look towards the offshore electrical grid, leading one directly into the grid bottlenecks of Section 5.

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# 5. The Electrification Illusion

While political roadmaps frequently treat green electricity as an infinite, frictionless utility, scaling water electrolysis to replace fossil feedstock hits severe spatial and physical limits.

Converting the entire Dutch ammonia fleet to a pure green hydrogen pathway requires **32.55 TWh of dedicated renewable electricity annually** (as detailed out in Section 2.3). This section maps out the physical surface area, offshore capacity targets, and transmission bottlenecks that prove that supplying green hydrogen for ammonia manufacturing solely via electrolysis is a mathematical impossibility within Dutch borders.

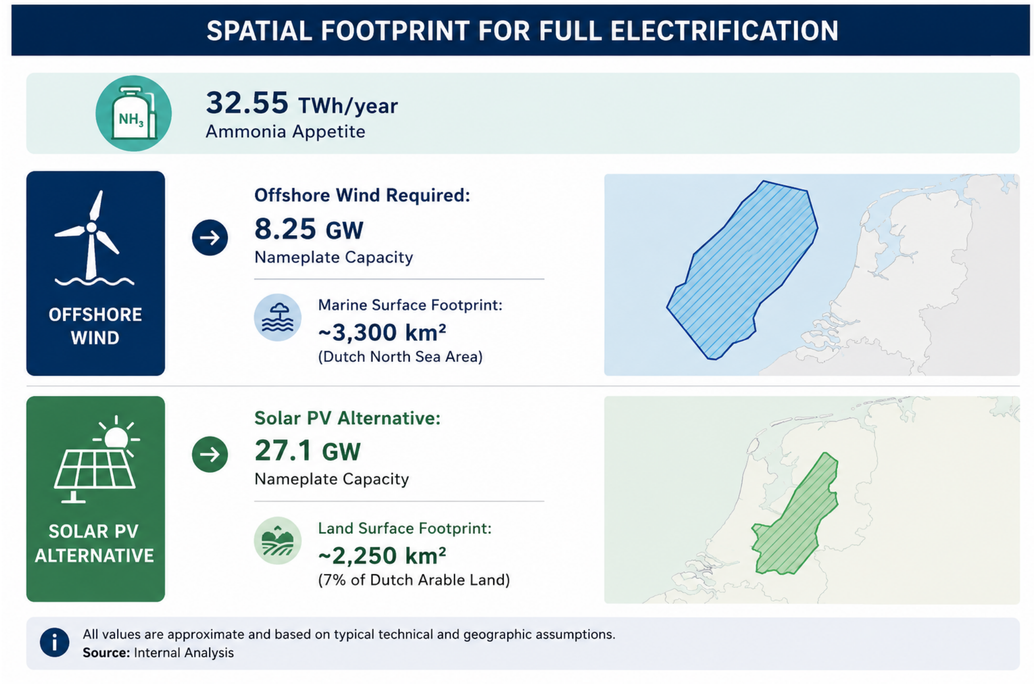
## 5.1. Power Density Mathematics

Renewable energy generation is governed by **low power density** - the amount of continuous electrical power generated per square meter of land or sea surface area ($W/m^2$). Unlike high-density fossil fuel or nuclear assets (which generate 1000-2000 $W/m^2$), renewable harvesting requires vast spatial footprints:

$$\text{Required Area, A} = \frac{P_{\text{nameplate}}}{\text{Power Density } D_p}$$

- **Offshore Wind Power Density (1.5 - 3.0 $W/m^2$)**: Modern offshore turbines (14-15 MW nameplate capacity) require wide array spacing - typically 8 to 10 rotor diameters apart - to prevent 'wake-effect' turbulence losses [1]. As a result, large-scale offshore wind farms yield an average effective power density of roughly 2.5 $W/m^2$ of marine surface area.

- **Solar Photovoltaic Power Density (5-20 $W/m^2$)**: Ground-mounted utility PV arrays in Northern European latitudes yield an annual average power density of roughly 10-12 $W/m^2$, accounting for night cycles, cloud cover, and inter-panel spacing [2]. The number 10-12 $W/m^2$ is actually on the higher end and quite optimistic. The actual number for The Netherlands is lower but this report uses the optimistic case, providing room for improvement in solar cell technology in the future.




(Image showing required area needed for offshore wind or solar PV)

If the two Dutch ammonia plants were to be catered by offshore wind powering the electrolysers to generate green hydrogen then, a total of **8.25 GW[1] of nameplate offshore wind capacity will be required** (at an average Dutch North Sea offshore wind capacity factor of 45%), and the wind turbines will occupy:

$$\text{Marine Area} = \frac{8.25 \times 10^9 \text{ W}}{2.5 \text{ W/m}^2} = 3.30 \times 10^9 \text{ m}^2 = \mathbf{3{,}300} \text{ km}^{\mathbf{2}}$$

A dedicated marine zone of 3300 km² represents nearly **6% of the entire Dutch Continental Shelf** reserved exclusively for these two chemical plants.

If on the other hand, the electrolysers supplying the green hydrogen are powered by solar PV then, **the nameplate capacity for solar PV arrays will have to be 27.1 GW[2]** and it would require ~2250 km² of land (at 12 W/m²

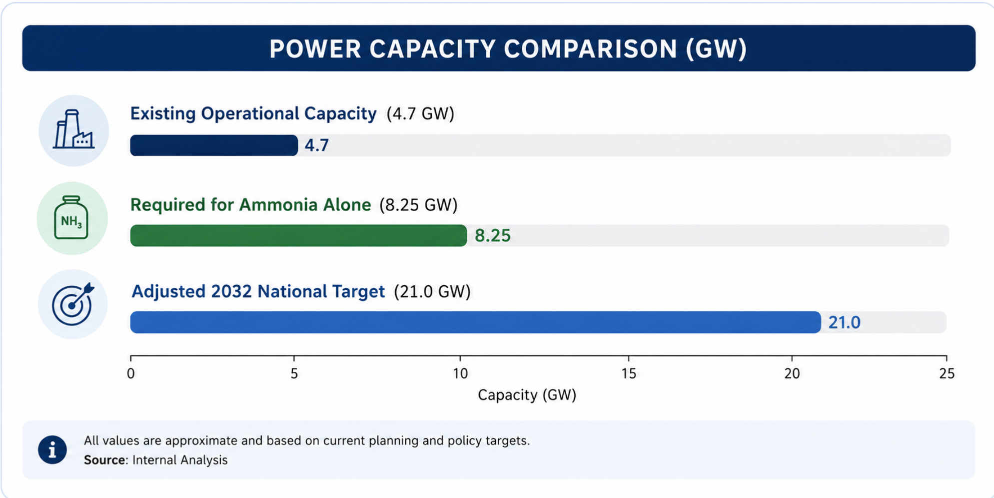
[1] The 8.25 GW nameplate capacity is gotten by dividing 32.55 TWh/year by the number of hours in a year (365 x 24) and then dividing the result by 0.45 (the average Dutch North Sea grid-delivered offshore wind capacity factor)

[2] The 27.1 GW nameplate capacity is gotten by dividing 32.55 TWh/year by the number of hours in a year (365 x 24) and then dividing the result by 0.137 (the average annual capacity factor of utility scale solar PV arrays in the Netherlands).

power density) - consuming **over 7% of the total arable farmland in the Netherlands**, creating immediate political conflict with the agricultural sector.

## 5.2. Operational Baseline vs. Future Targets

The expansion of Dutch offshore wind in the North Sea is one of the most ambitious marine engineering projects in Europe. However, comparing real-world deployment milestones against industrial timelines reveals a massive operational deficit.




- **Current Operational Fleet (4.74 GW)**: Spread across wind farms such as Borssele, Hollandse Kust Zuid, and Hollande Kust Noord, the Netherlands currently maintains 4.74 GW of operational offshore wind [3].
- **The 2032 Adjusted Target (21.0 GW)**: The Dutch government initially targeted 21 GW by 2030, but supply chain inflation, turbine manufacturing bottlenecks and grid landing delays pushed the commissioning of major projects (such as IJmuiden Ver and Nederwiek) to 2032/2033 [4].

## 5.3. Grid Infrastructure Barriers: Netcongestie & Landing Friction

Even if offshore turbines were erected tomorrow, transmitting tens of gigawatts of variable wind power to inland chemical clusters faces unprecedented grid bottlenecks.

a) Severe High-Voltage Netcongestie (Grid Congestion)

The Dutch transmission grid, operated by **TenneT**, is already operating at full capacity. Across all twelve Dutch provinces, high-voltage substations are locked in a state of severe *netcongestie*. Over **12,000 industrial users and energy projects are currently on waiting lists** [5] for grid capacity extensions.

Adding 8.25 GW industrial baseload electrolyser draw onto this network would trigger structural blackouts without massive, multi-decade transformer upgrades.

b) Landing Cable friction & Pipeline delays

Bringing North Sea power ashore requires massive High-Voltage Direct Current (HVDC) land corridor connections. The strategic **Delta Rhine Corridor (DRC**) - designed to funnel offshore electricity and green hydrogen from coastal ports (Rotterdam and Zeeland) to the inland industrial clusters of Chemelot and the German Ruhr Valley - has suffered repeated planning and environmental permitting delays.

As TenneT noted, prioritising hydrogen pipelines over planned high-voltage direct-current cables risks adding over **€400 million in annual congestion management costs** [6].

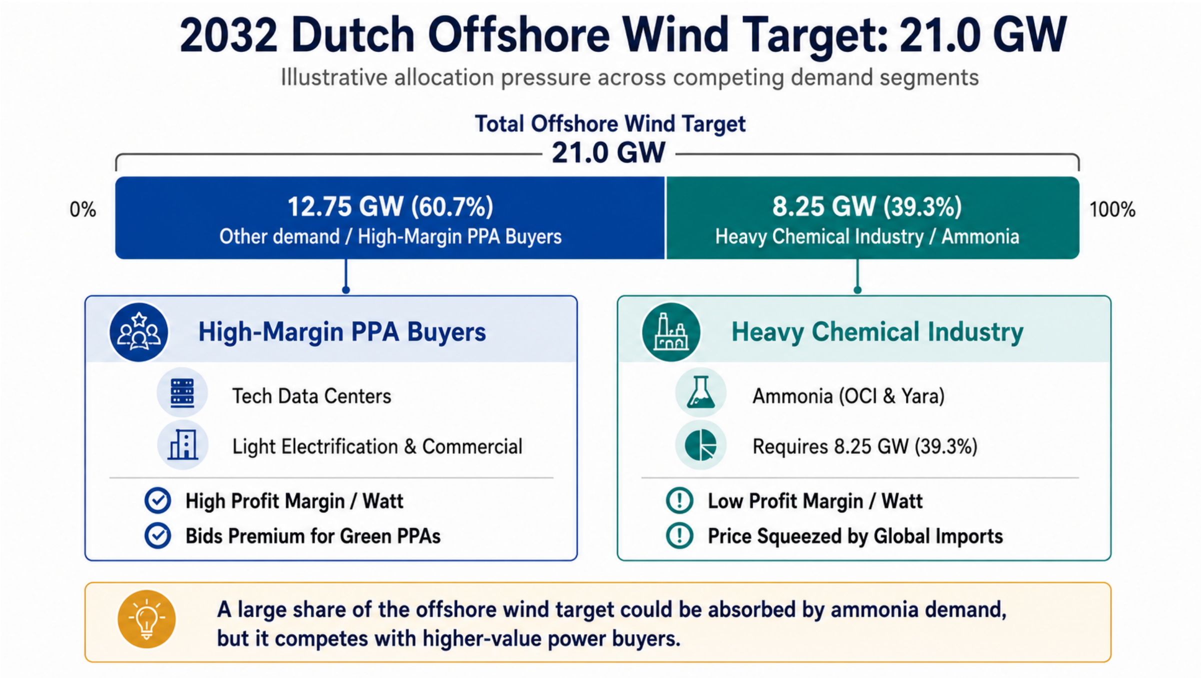
## 5.4. The Deficit Footprint & Corporate PPA Dynamics

The ultimate barrier to the pure electrification route of the green hydrogen needed for the two ammonia plants is economic cannibalisation within the Power Purchase Agreement (PPA) market.

If Yara Sluiskil and OCI Chemelot were to fully electrify (via electrolysers), **their 8.25 GW demand would swallow 39.3% - nearly two-fifths - of the total national offshore wind buildout projected for 2032**.

The remaining 60.7% of the national wind fleet would have to power:

- Electric vehicles, heat pumps, and public rail networks.
- The entire rest of Dutch heavy manufacturing
- Tech multinationals (e.g. Google, AWS data centres).




## 5.5. Corporate PPA Monopoly & Key Takeaway

Due to the fact that hyper-scale data centres yield significantly higher profit margins per Megawatt-hour consumed than a commodity chemical plant, tech giants can afford to outbid chemical manufacturers for long-term renewable PPAs.

If Yara or OCI attempt to buy 32.55 TWh of electricity at market PPA rates (~€50 to €90 per MWh [7]), their electricity cost alone would add **€525 to €945 per ton of ammonia**, making Dutch ammonia twice as expensive as global market imports.

A pure electrification strategy (via electrolysers supplying green hydrogen) creates a structural deadlock. The Netherlands lacks the spatial room, grid bandwidth, and offshore capacity to support the chemical sector through green power alone.

This physical constraint validates the core thesis of this report: **a hybrid deployment model preserving a biogenic methane baseline is not just and alternative option- it is a physical necessity**.

# References

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[3] https://nedzero.nl/en/offshore-wind-facts

[4] https://iea-wind.org/wp-content/uploads/2025/11/Netherlands.AnnualReport2024.publish.pdf

[5] https://ioplus.nl/en/posts/thousands-of-companies-added-to-waiting-list-for-power-grid

[6] https://www.acm.nl/system/files/documents/updated-advance-communication-on-the-use-of-congestion-income-tennet-2026.pdf

[7] https://www.linkedin.com/pulse/ppa-country-profile-netherlands-synertics-5n9ee/

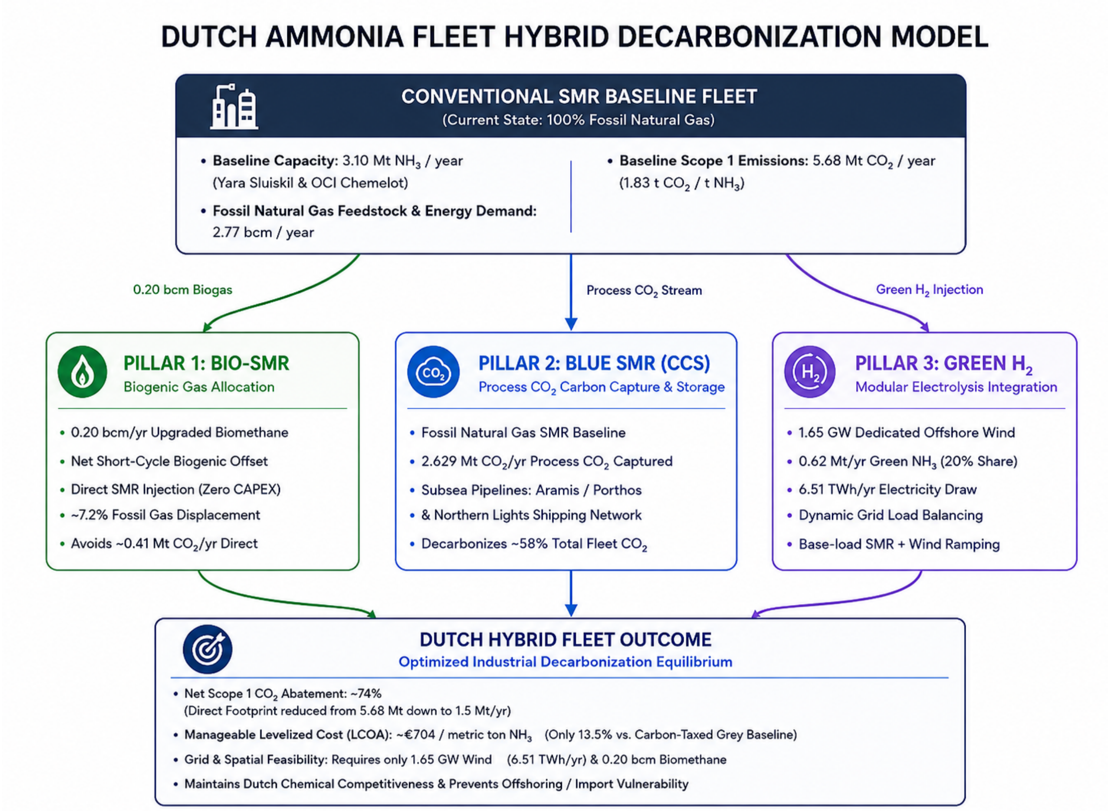
# 6. Modelling the Domestic Hybrid Solution

Neither a 100% green hydrogen conversion nor a pure bio-methane swap is physically or economically feasible for the Dutch ammonia fleet by 2030-2035. A pure green hydrogen pathway demands nearly a third of the nation's grid electricity (32.55 TWh/year), while a pure bio-methane swap would exhaust 154% of the nation's total practical biogenic gas potential (2.77 bcm/year required vs. 1.8 bcm/year total domestic cap).

To avoid industrial closure or offshoring, the Netherlands must deploy a **pragmatic Domestic Hybrid Architecture.** This model combines targeted biogenic gas collection, carbon capture and subsea storage (CCS), and modular green hydrogen electrolysis systems to achieve deep carbon abatement within current infrastructure and energy constraints.

## 6.1. Architecture of the Three-Pillar Hybrid Model

The proposed domestic hybrid model optimises three distinct decarbonisation mechanisms based on their thermodynamic efficiency, market availability, and capital readiness.



- Pillar 1: Biogenic Gas Allocation (Bio-SMR)

  The mechanism that must be in place for the success of this pillar is to **secure the baseline allocation of 0.2 bcm/year** of domestic upgraded bio-methane via long-term bilateral Power/Gas Purchase Agreements (PPAs) and corporate green gas certificates.

  This bio-methane needs to be injected directly into existing SMR reformer loops at Yara Sluiskil and OCI Chemelot. No plant retrofits, capital expenditure or catalyst changes will be required as a result of this measure. The immediate impact of doing this is will **result in replacement of ~7.2% of fossil natural gas** feedstock with short-cycle biogenic carbon, providing immediate, zero-CAPEX carbon displacement.

- Pillar 2: Process $CO_2$ Capture and Storage

  For this pillar to succeed, the required mechanism/process to be in place is to **capture the high-purity $CO_2$ stream emitted during the water-gas shift reaction** ($CO + H_2O \rightarrow CO_2 + H_2$) in existing SMR units. The existing SMR units contribute to 80% share of total ammonia production.

  **Process emissions represent ~58% of total plant $CO_2$ output** (1.06 tons $CO_2$ per ton of $NH_3$). The concentrated, near-pure $CO_2$ stream is then compressed, liquefied, and piped to subsea offshore geological storage. For the two ammonia plants in the Netherlands, this would look as follows:

  *Yara Sluiskil*: The $CO_2$ is transported via the commercial Northern Lights subsea shipping network (800,000 tons/year initial capacity and scaling up)

  *OCI Chemelot*: The $CO_2$ is transported via the Delta Rhine Corridor (DRC) pipeline network to the Aramis/Porthos North Sea offshore storage hubs.

  The impact of doing this will result in a **capture of 2.629[3] million metric tons of $CO_2$ per year**, decarbonising the vast majority of the remaining fossil gas baseline.

- Pillar 3: Modular Green Hydrogen Integration

  The most pragmatic way to incorporate electrolysers and green hydrogen into the picture is to **co-locate water electrolysis units** (AWE or PEM) **totalling 1.65 GW of nameplate capacity**, powered by dedicated corporate PPAs with new offshore wind farms (such as Hollandse Kust West or IJmuiden Ver).

[3] The emissions are coming from producing 2.48 Mt of $NH_3$ and the need for gas (fossil & bio-methane) for the same. The remaining 0.62 Mt of $NH_3$ is produced via green hydrogen and hence must not be accounted for emissions.

Green hydrogen produced is injected directly into the Haber-Bosch synthesis loop alongside hydrogen produced by the SMR reformer. This allows the plants to operate as flexible loads - drawing peak offshore wind power during periods of low grid demand and turning down electrolysis when grid electricity prices spike.

A detailed explanation on how this pillar and mechanism adds flexibility to the Haber-Bosch synthesis loop is given in Appendix 2.

The impact of implementing this will be **generation of 0.62 million metric tons of green ammonia per year** (~20% of total Dutch ammonia production capacity), requiring just 6.51 TWh/year of electricity in comparison to 32.55 TWh/year of electricity in the 'green hydrogen' ONLY route.

## 6.2. Quantitative Mass Balance & Scenario Comparison

The table below contrasts the operational parameters of the conventional baseline against the extreme single-technology options and the proposed Dutch Hybrid Model:

| **Performance & Operational Metric** | **Baseline (100% Fossil SMR)** | **Scenario A (100% Green H2)** | **Scenario B (100% Bio-methane)** | **Proposed Dutch Hybrid Model** |
|---|---|---|---|---|
| Annual $NH_3$ output | 3.1 Mt | 3.1 Mt | 3.1 Mt | 3.1 Mt |
| Fossil Natural Gas demand | 2.77 bcm/year | 0.00 bcm/year | 0.00 bcm/year | 2.02 bcm/year |
| Bio-methane demand | 0.00 bcm/year | 0.00 bcm/year | 2.77 bcm/year | 0.2 bcm/year |
| Electricity Draw | ~0.6 TWh/year * | 32.55 TWh/year | ~0.6 TWh/year * | 7.11 TWh/year # |
| Dedicated Offshore Wind needed | 0.00 GW | 8.25 GW | 0.00 GW | 1.65 GW |
| Subsea $CO_2$ captured & stored | 0.00 Mt/year | 0.00 Mt/year | 0.00 Mt/year | 2.629 Mt/year |
| Net Direct Scope 1 $CO_2$ footprint | 5.68 Mt/year | 0.00 Mt/year | 0.00 Mt/year | 1.5 Mt/year |
| Direct Scope 1 carbon reduction | 0% | 100% | 100% | ~73.6% |

*Needed for plant operations, # Electrolyser power input + plant operations

The fossil natural gas demand for the proposed hybrid model drops to 2.02 bcm/year. The math here is quite straightforward, 0.2 bcm comes from bio-methane and the remaining 0.55 bcm is avoided due to green hydrogen production from onsite co-located electrolysers.

The Net Direct Scope 1 $CO_2$ footprint for the proposed hybrid model is calculated as follows:

- From Pillar 1:

  It was detailed out in *Section 4.3* that 2.05 Mt of $CO_2$ can be saved per bcm of bio-methane used. Therefore, **0.2 bcm of bio-methane results in 0.41 Mt of $CO_2$ from being emitted**.

- From Pillar 2:

  It was mentioned above that 2.629 Mt of $CO_2$ can be captured from process emissions.

- From Pillar 3:

  Since 0.62 million metric tons of ammonia is produced from green hydrogen (via electrolysers), it immediately **avoids 1.14 Mt of $CO_2$**. It was mentioned in *Section 1.2* that 1.83 tons of $CO_2$ are emitted for every ton of ammonia produced.

## 6.3. Levelised Cost of Ammonia (LCOA) Analysis

The economic viability of the transition hinges on the Levelised Cost of Ammonia (LCOA) per metric ton. **A pathway that delivers zero emissions but doubles manufacturing costs will cause production to leak to regions with cheaper energy** (e.g. the US Gulf Coast or the Middle East).

Without diving into granular project-finance modelling, all four pathways are evaluated under a standardised five-component additive LCOA framework. Every cost figure is expressed in € per metric ton of ammonia produced (€/ton $NH_3$)

$$\text{LCOA}\left(\frac{€}{\text{ton NH}_3}\right) = C_{\text{CAPEX,OPEX/Fixed}} + C_{\text{Gas}} + C_{\text{Power}} + C_{\text{CCS}} + C_{\text{Tax}}$$

Where:

$C_{CAPEX,OPEX/Fixed}$ = Annuitized capital expenditure (equipment, electrolyser, retrofits) and fixed operations & maintenance (O&M, site labour, catalysts)

$C_{Gas}$ = Natural gas or bio-methane feedstock and fuel costs

$C_{Power}$ = Dedicated renewable electricity purchase costs (e.g. offshore wind PPAs)

$C_{CCS}$ = Carbon capture, pipeline transport, and subsea geological storage tariffs.

$C_{Tax}$ = Scope 1 carbon penalty under EU ETS 1 scheme

## LCOA cost matrix:

| **Cost components** | **Baseline (100% Fossil SMR)** | **Scenario A (100% Green $H_2$)** | **Scenario B (100% Bio-methane)** | **Proposed Dutch Hybrid Model** |
|---|---|---|---|---|
| $C_{CAPEX,OPEX/Fixed}$ (€/ton) | 160.6 | 310 | 160.6 | 190 |
| $C_{Gas}$ (€/ton) | 313 | 0 | 1099.6 | 252# |
| $C_{Power}$ (€/ton) | 0 | 840 | 0 | 168 |
| $C_{CCS}$ (€/ton) | 0 | 0 | 0 | 55.12 |
| $C_{Tax}$ (€/ton) | 146.4 | 0 | 0 | 38.71 |
| LCOA (€/ton $NH_3$) | **620** | **1150** | **1260** | **~704** |

# With Dutch SDE++ subsidies

Detailed calculations and explanations for the LCOA numbers in the above table is given in Appendix 3.

Note: This is a very high-level LCOA calculation without diving deep into the specifics of the ammonia plant or electrolyser equipment or other components of the equation. The numbers in the table above present a ballpark range. A more detailed LCOA will be will be very helpful but is out of the scope for this report.

The key economic takeaway is:

*The proposed hybrid model achieves a 74% reduction in Scope 1 emissions while increasing manufacturing costs by a manageable ~13.5% relative to carbon-taxed fossil production. This keeps Dutch assets relatively cost-competitive with imported global ammonia.*

## 6.4. Transition Roadmap: Phased Implementation (2026-2035)

To navigate technology readiness levels and pipeline construction lead times, the hybrid transition is to be executed in three distinct operational phases:

**Phase 1: Regulatory Integration & Bio-methane Injection**

(2026-2028)

- **CBAM Alignment & Verification**: Establish actual-emissions tracking protocols at Rotterdam and Terneuzen port gates to ensure imported fertiliser cargoes reflect full embedded carbon costs.
- **FEED & permitting**: Finalise Front-End Engineering Design (FEED) for SMR process-stream amine absorption retrofits and dynamic synthesis loop controls.
- **Gas Feedstock**: Secure long-term bilateral contracts (15 years) for 0.2 bcm/year of grid bio-methane under Dutch Green Gas certificate standards for Yara Sluiskil and OCI Chemelot

**Phase 2: Modular Electrolysis Ramp-Up & Subsea CCS Connections**

(2028-2030)

- **Stage 1 Modular Electrolysis**: Construct co-located 500 MW water electrolysis units at Yara Sluiskil and 350 MW units at Chemelot. This will introduce 10% green hydrogen blend into the Haber-bosch synthesis loop.
- Execute off-take PPAs tied to new North Sea offshore wind tenders.
- **Aramis/Porthos Pipeline Commissioning**: Complete tie-ins from Sluiskil and Chemelot to offshore subsea trunklines, initiating capture and sequestration of 2.629 Mt $CO_2$/year of process emissions.
- **Infrastructure Access**: Connect facility networks to the initial segments of the Delta Rhine Corridor (DRC) for cross-border hydrogen and $CO_2$ transport

**Phase 3: Deep hybrid Optimisation**

(2031-2035+)

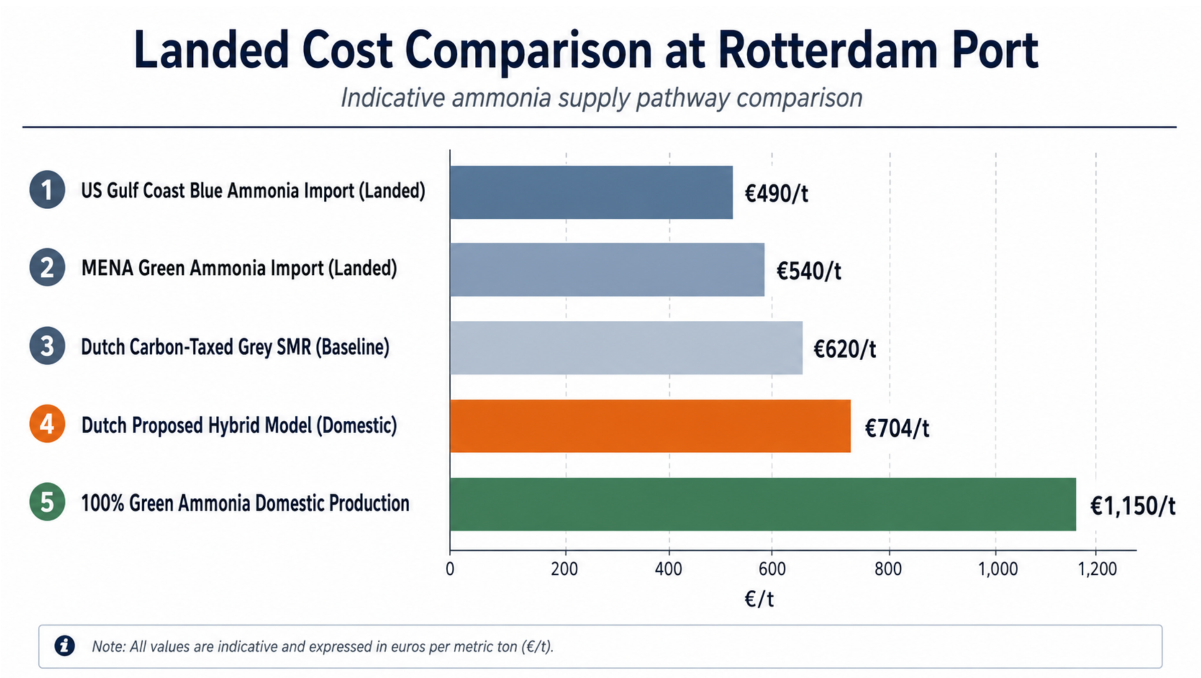
- **Electrolysis Expansion**: Expand total fleet electrolyser capacity to 1.65 GW, reaching the full 20% green hydrogen production share (0.62 Mt/year green $NH_3$).
- Expand CCS infrastructure to capture secondary flue gas $CO_2$ emissions using advanced amine solvent retrofits on reformer furnaces.
- Evaluate second-generation high-temperature solid oxide electrolyser (SOEC) retrofits using waste heat from Haber-Bosch loops to further lower unit power consumption.

# 7. Policy Framework, Import Safety Valve & Strategic Outlook

While Section 6 demonstrates that the **Proposed Dutch Hybrid Model** achieves an **73.6% Scope 1 carbon reduction** at a levelled cost of **€704/metric ton $NH_3$**, this domestic production cost must be evaluated against emerging global market dynamics.

## 7.1. Domestic Hybrid Production vs. Import Parity Dynamics

The Netherlands faces an impending commercial tension: overseas exporters in regions with abundant low-cost natural gas and geological storage (e.g. US Gulf Coast) or high solar/wind capacity factors (e.g. Middle East, North Africa) are projecting landed cost at port of Rotterdam between **€480 and €560 per metric ton[4]**.




Relying entirely on low-cost imported ammonia exposes the Netherlands and the broader European agricultural sector to severe strategic risks:

[4] https://www.kbr.com/sites/default/files/documents/2024-10/KBR_Paper_Europe_Ammonia.pdf

- **Chemical Fleet Deindustrialisation**:

  Complete closure of domestic primary reforming loops (Yara Sluiskil and OCI Chemelot) would permanently destroy high-skilled industrial jobs and erode core chemical engineering capabilities in Northwest Europe.

- **Supply Chain & Geopolitical Vulnerability**:

  Shifting 3.1 Mt/year of baseline ammonia demand to maritime import logistics exposes essential nitrogen fertiliser inputs to global shipping bottlenecks, choke-point disruptions, and geopolitical coercion.

- **Loss of Downstream Integration**:

  Domestic SMR facilities produce high-purity process $CO_2$ as an essential byproduct for on-site urea synthesis, industrial grade $CO_2$ supply, and local food/beverage industries. Complete shutdown disrupts integrated chemical park economics across the Rotterdam-Geleen axis.

### The 'Import Safety Valve' Model

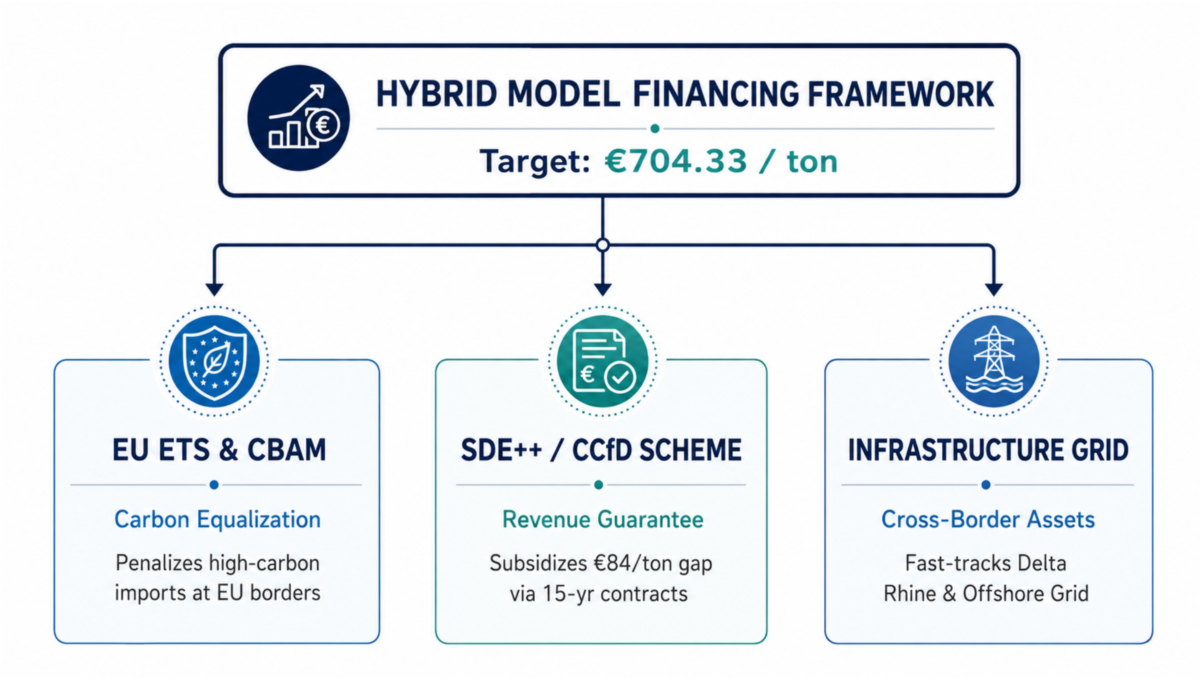
Rather than viewing imports and domestic manufacturing as mutually exclusive, the Dutch chemical cluster should leverage an **Import Safety Valve Strategy**:

- **Domestic Core (3.1 Mt/year Base Load)**: Protect and maintain domestic hybrid production at Sluiskil and Chemelot as an essential strategic anchor, supplying core regional agricultural and industrial demand.

- **Import Expansion Layer**: Utilise world-class import terminal infrastructure under development at the Port of Rotterdam to absorb demand growth, seasonal agricultural peaks, and chemical sector expansions without incurring domestic grid congestion or land-use constraints.

## 7.2. Policy Instruments & Market Enablers

Bridging the **€84/ton price differential**, for $NH_3$, between the carbon-taxed fossil baseline (€620/ton) and the Proposed Dutch Hybrid Model (€704/ton) requires a coordinated policy framework to prevent carbon leakage and ensure project bankability.




- EU Carbon Border Adjustment Mechanism (CBAM)

  The definitive implementation of CBAM levels the playing field by imposing carbon equalisation tariffs on imported nitrogen fertilisers and chemical intermediates based on their embedded emissions intensity.

  As EU ETS free allocation allowances are phased out, CBAM prevents high-emission overseas suppliers (e.g. unmitigated fossil production in Asia or Latin America) from undercutting domestic producers. For the CBAM to be effective, rigorous and verified actual-emissions tracking protocols must be ensured at EU port gates to avoid circumvention via default emission value loopholes.

- Carbon Contracts for Difference (CCfD) & SDE++ Optimisation

  To incentivise long-term private capital expenditure into offshore CCS connections and electrolyser deployment, state subsidy frameworks must provide revenue certainty.

  The Dutch SDE++ scheme (*Stimulating Duurzame Energieproductie en Klimaattransitie*) must structure targeted 15 year Carbon Contracts for Difference (CCfDs). The CCfD pays industrial operators the difference between the actual strike price of the hybrid facility (€704/ton) and the prevailing market reference price (grey ammonia baseline), guaranteeing bankable cash flows during initial debt amortisation periods.

- Accelerated Energy & Transport infrastructure deployment

  The physical execution of the hybrid model hinges on cross-border utility infrastructure:

  **Delta Rhine Corridor (DRC)**: Regulatory approvals must be fast-tracked and construction of the cross-border pipeline corridor connecting the Port of Rotterdam, Chemelot, and North Rhine-Westphalia to transport both captured $CO_2$ (to Aramis/Porthos storage) and pure green hydrogen.

  **North Sea Offshore Grid Expansion**: Timely delivery of TenneT's 2 GW offshore grid connection hubs to supply dedicated power for the 1.65 GW electrolyser fleet at competitive long-term PPA rates (€80/MWh).

## 7.3. Strategic Policy Action Matrix

The table below synthesises the core operational barriers, required policy mechanisms, and institutional stakeholders needed to realise the 3.1 Mt/year ammonia production via the hybrid model.

| Financial/Technical Barrier | Target Policy Level | Primary Stakeholder | Operational Mechanism & Implementation Timeline |
|---|---|---|---|
| High Capital Expenditure for Electrolyzers (1.65 GW) | SDE++ Subsidies & IPCEI Grants | Dutch Ministry of Climate Policy & Green Growth | Grant co-funding for $C_{CAPEX/Fixed}$ electrolyzer installation (€1,200/kW) to reduce upfront capital burden |
| PPA Power Costs (€80/MWh) vs. Market Volatility | Offshore Wind Tender Integration & CCfDs | TenneT / Dutch Energy Agency (RVO) | Direct pairing of offshore wind tenders with dedicated industrial hydrogen off-take agreements to lock in long-term power rates |
| CCS Infrastructure Tariffs (€65/t $CO_2$) | Aramis / Porthos State Guarantees | Gasunie / EBN / Port of Rotterdam | State underwriting of volumetric volume risks on subsea transmission trunklines to cap transport tariffs |
| Carbon Leakage from Unregulated Third-Country Imports | EU CBAM Enforcement & ETS Phase-Out | European Commission / Dutch Customs | Strict verification of embedded emissions for landed ammonia cargoes starting in 2026 to ensure fair competition |
| Cross-Border Pipeline Bottlenecks | Delta Rhine Corridor (DRC) Statutory Status | Dutch/German Ministries of Energy & Infrastructure | Granting national priority project status to accelerate environmental permitting for $CO_2$ and $H_2$ pipelines. |

# 8. Concluding Strategic Outlook

The Dutch chemical sector stands at a critical juncture between forced deindustrialization and climate leadership. Continued reliance on unmitigated fossil reformers will expose domestic assets to escalating EU ETS tax penalties, while an immediate pivot to full electrification would destabilise factory economics and strain North Sea grid capacity.

The Proposed Dutch Hybrid Model provides a pragmatic, mathematically sound, and economically bankable transition pathway. By pairing offshore carbon capture with targeted bio-methane displacement and modular green hydrogen expansion, **the Netherlands can preserve its 3.10 Mt/year primary chemical manufacturing core, safeguard regional food and industrial security, and achieve a 73.6% reduction in Scope 1 direct emissions at a manageable cost premium of 13.6%**.

Timely alignment of EU CBAM enforcement, SDE++ Carbon Contracts for Difference (CCfDs), and cross-border pipeline infrastructure will secure the Netherlands' position as Western Europe's leading hub for sustainable nitrogen chemistry.

## Disclaimer:

This report has been written by Dr. Vikrant Venkataraman, Director & Founder of VenkaCon Consulting (www.venkacon.com). The analysis and data are based on pure facts that is available on the internet and the opinions expressed are solely meant for providing a practical, holistic, and commercial view on the subject of decarbonisation pathways of ammonia plants in The Netherlands and to throw light on what can be pragmatically achieved.

# Appendix 1

To calculate the net systemic $CO_2$ saved per 1.0 bcm of bio-methane allocated, we evaluate the baseline chemistry and fossil energy displacement for each sector.

### Baseline Energy Content of 1.0 bcm Bio-methane

1.0 bcm = 1,000,000,000 $m^3$

At a Lower Heating Value (LHV) of 35.8 MJ/$m^3$:

Total Energy Volume = $1.0 \times 10^9$ $m^3$ x 35.8 MJ/$m^3$ = $35.8 \times 10^9$ MJ

### Sector 1: Heavy Transport & Shipping (Displacing Heavy Fuel Oil/ Diesel)

Displaced Fuel Emission Factor: Heavy marine Gas Oil/Diesel carries a carbon intensity of ~74.1 g $CO_2$/MJ (or 0.0741 kg $CO_2$/MJ).

Direct $CO_2$ displaced = $35.8 \times 10^9$ MJ x 0.0741 kg $CO_2$/MJ

= $2.65 \times 10^9$ kg $CO_2$

= 2.65 Million metric tons of $CO_2$ saved / bcm

### Sector 2: Ammonia Manufacturing (Displacing Natural Gas SMR Feedstock + Process heat)

Displaced Chemistry: Conventional Steam Methane Reforming (SMR) consumes 894 $m^3$ of fossil gas per ton of $NH_3$ and emits 1.83 tons of $CO_2$ per metric ton of $NH_3$ (combining combustion emissions and process reaction stoichiometry)

Total ammonia produced by 1.0 bcm gas:

(1,000,000,000 $m^3$ bio-methane) / (894 $m^3$/ton NH3) = 1,118,568 metric tons $NH_3$

Total avoided $CO_2$

1,118,568 metric tons $NH_3$ x 1.83 tons $CO_2$/ ton NH3 = 2.047 x $10^6$ tons CO2

= 2.05 Million metric tons of $CO_2$ saved / bcm

**Sector 3: Built Environment (Displacing Grid Natural gas for Domestic Boilers)**

Displaced Fuel Emission Factor: Standard natural gas combustion emits 56.1 g $CO_2$/MJ (or 0.0561 kg $CO_2$/MJ)

Combustion $CO_2$ savings = 35.8 x $10^9$ MJ x 0.0561 kg $CO_2$/MJ

= 2.008 x $10^9$ kg $CO_2$

= 2.008 Million metric tons of $CO_2$ saved / bcm

Note:

The $CO_2$ saved in each sector corresponds directly to swapping a fossil fuel with bio-methane whose carbon was recently fixed from atmospheric $CO_2$ by organic matter via photosynthesis.

Due to the fact that biogenic combustion is carbon-neutral in short-term natural cycles (net combustion $CO_2$ = 0), every gigajoule of fossil fuel displaced yields a gross abatement equal to 100% of the fossil fuel's direct combustion emission factor.

# Appendix 2

## How green hydrogen adds flexibility to ammonia plants?

A conventional Haber-Bosch reactor operates under punishing conditions - temperatures between 400 $^{o}$C and 500 $^{o}$C and pressures of 150 to 250 bar.

**SMR Limitations**: A Steam Methane Reformer (SMR) cannot easily be turned down below 60% - 80% of nameplate capacity. Thermal shocks from ramping up or down damage reformer furnace tubes and deactivate the nickel catalysts.

**Pure Green Limitations**: If an ammonia plant relies 100% on offshore wind or solar power, the electrolyzers will ramp up and down violently as the weather changes. Forcing a Haber-Bosch reactor to constantly cycle between 0% and 100% load causes severe thermal stress, rapid iron-catalyst degradation, and requires massive, multi-million-euro high-pressure hydrogen buffer storage tanks to smooth out the flow.

## Base-Load + Dynamic Augmentation

In the proposed Dutch hybrid model, the plant operates as a synchronised dual-feed system.

**SMR maintains the Thermal Floor** - The SMR baseline (running on gas + CCS) supplies a constant stream of syngas that keeps the ammonia synthesis loop running at a steady ~80% base load. This keeps the reactor vessel (for ammonia production) at thermal equilibrium (450 $^{o}$C) and maintains system pressure, protecting the catalyst beds and avoiding thermal shocks.

**Water Electrolyzers provide the Dynamic Ceiling** - Water electrolyzers (specifically PEM or Alkaline systems) can ramp their production from 0% to 100% in a matter of seconds to minutes.

<u>High Wind / Low Power Prices</u>: When North Sea wind farms produce excess electricity (or power prices drop to near zero/negative), the 1.65 GW electrolyzer array ramps up to maximum capacity. The resulting green $H_2$ is compressed and injected directly into the synthesis loop alongside the SMR syngas, driving total ammonia output up to 100%.

<u>Low Wind / High Power Prices</u>: When the wind stops or grid power prices spike, the electrolyzer array ramps down to 0%. The Haber-Bosch loop simply throttles back from 100% to its 80% SMR baseline output.

The combination of the following factors - *80% SMR baseline output*, *the Netcongestie issues*, *the economic LCOA squeeze* and *the Offshore Wind market competition* is the reason why the the electrolyser nameplate capacity is capped at 1.65 GW.

## Major Operational & Economic Advantages

- **Elimination of Massive $H_2$ Buffer Storage**: In a pure green facility, bridging a 24-hour calm period requires enormous hydrogen storage vessels or underground salt caverns. In the proposed hybrid setup, the SMR acts as an internal "thermal battery", eliminating the need for massive intermediate $H_2$ storage tanks.
- **Power Market Arbitrage & Grid Revenue (Demand Response)**: The 1.65 GW electrolyzer array allows Yara and OCI to act as major grid balancers for the national grid operator TenneT. By consuming massive electricity during off-peak wind hours and shedding that 1.65 GW load instantaneously when the grid is strained, the plants avoid high peak tariffs and can sell primary frequency containment reserve (FCR) services back to the grid.
- **Optimized Compressor Operations**: Because the ammonia synthesis loop only fluctuates between 80% and 100% capacity (rather than 0% to 100%), the gas synthesis compressors remain within their optimal operating efficiency window, avoiding costly gas anti-surge recycling losses.

Injecting green hydrogen into an SMR-anchored Haber-Bosch loop gives the plant the best of both worlds: the thermal stability and continuous operation of an industrial chemical plant, combined with the extreme responsiveness of modern power-to-gas technology.

# Appendix 3

## Breakdown of the different components for the LCOA.

- Baseline (100% Fossil SMR)
  - $C_{CAPEX,OPEX/Fixed}$: Existing plant and thus no major CAPEX costs, fixed O&M (water treatment, catalyst replacement and sustaining capital). The approximate costs for this component per ton of $NH_3$ is **€160.6**[5]
  - $C_{Gas}$: 894 $m^3$ of natural gas is required per ton of $NH_3$ at TTF (Title Transfer Facility) wholesale gas rate of €35.0/MWh[6] (€0.35/$m^3$), leading to **€313** per ton of $NH_3$.
  - $C_{Power}$ & $C_{CCS}$: No electrolysis systems or carbon capture and storage technologies deployed and hence these components amount to **zero.**
  - $C_{Tax}$: Full scope 1 intensity of 1.83 t $CO_2$/ t $NH_3$ exposed to EU ETS1 carbon prices at €80.00/t $CO_2$, giving **€146** per ton of $NH_3$.

- Scenario 1 (100% Green $H_2$)
  - $C_{CAPEX,OPEX/Fixed}$: Annuitized CAPEX for utility-scale PEM/Alkaline electrolysers (€1200/kW installed)[7], stack replacements, and synthesis loop modifications. This amounts to roughly **€310** per ton of $NH_3$.
    - The above figure is split into annuitized Electrolyser CAPEX at **€198** per ton $NH_3$, annuitized ASU & synthesis loop at **€48** per ton $NH_3$ and fixed O&M and stack replacement at **€64** per ton $NH_3$.
  - $C_{Gas}$: No necessity of fossil gas or bio-methane and therefore this amounts to **zero.**
  - $C_{Power}$: 10.5 MWh electricity consumption per ton $NH_3$ via dedicated offshore wind PPAs at €80/MWh. This amounts to **€840** per ton of $NH_3$.

[5] Reference: https://iea.blob.core.windows.net/assets/6ee41bb9-8e81-4b64-8701-2acc064ff6e4/AmmoniaTechnologyRoadmap.pdf

[6] https://www.ice.com/products/27996665/Dutch-TTF-Natural-Gas-Futures/data?marketId=6277387&span=3

[7] O. Schmidt, A. Gambhir, I. Staffell, A. Hawkes, J. Nelson, S. Few, Future cost and performance of water electrolysis: An expert elicitation study, https://doi.org/10.1016/j.ijhydene.2017.10.045

- $C_{CCS}$: There are no costs involved with capturing carbon dioxide and storing it, therefore costs associated with this component is **zero**.
- $C_{Tax}$: No direct scope 1 emissions and hence amounts to **zero**.

• Scenario 2 (100% Bio-methane)

- $C_{CAPEX,OPEX/Fixed}$: Identical to fossil natural gas, bio-methane is a direct drop-in fuel. The approximate costs for this component per ton of $NH_3$ is **€160.6**
- $C_{Gas}$: 894 $m^3$ of bio-methane input is required at long-term contracted industrial feedstock prices. This is projected to be **€1.23/m³** in the Netherlands by 2030, assuming some subsidy integration or long-term off-take pricing, rather than spot-market bidding against high-WTP transport fuel suppliers. This component amounts to **€1099.6** per ton of $NH_3$.
- $C_{Power}$ & $C_{CCS}$: There are no dedicated PPAs needed or carbon dioxide capture and storage, hence these components amount to **zero**.
- $C_{Tax}$: Biogenic emissions incur zero EU ETS tax liability and therefore this component amounts to **zero**.

• Proposed Dutch hybrid model

- $C_{CAPEX,OPEX/Fixed}$: The existing plant along with an electrolyser fleet will be used. Therefore, a blended fixed O&M combining SMR operations with the localised 1.65 GW electrolyser fleet share will contribute to this component and that amounts to ~**€190**
- $C_{Gas}$: Reduced fossil natural gas footprint combined with long-term contracted bio-methane. The fossil gas share is 72.9% and the bio-methane share is 7.2%. This component adds up to ~**€307** per ton of ammonia without subsidies and adds up to ~**€252** per ton of ammonia with Dutch SDE+++ (Stimulating Duurzame Energieproductie) subsidy of **€0.88/m3** of gas.
- $C_{Power}$: Since 20% of the ammonia production comes from electrolysis systems and the power draw of 1.65 GW is 20% of the 8.25 GW (in Scenario1, 100% green hydrogen), the $C_{Power}$ term amounts to **€168**.

- $C_{CCS}$: Subsea transport and injection tariffs at €65.0/t $CO_2$[8] are applied to captured process emissions across the remaining SMR fleet. 80% of the total ammonia production comes from fossil gas and bio-methane. A total of 2.629 Mt of $CO_2$ are captured, resulting in an annual cost of €170.88 million per year and when this is calculated per ton of NH3, results in a figure of **€55.12** per ton of ammonia (taking into account total 3.1 Mt of ammonia production per year).
- $C_{Tax}$: Full scope 1 intensity of 1.5 Mt $CO_2$/year are applied. This is covered to $CO_2$ emissions per ton of $NH_3$ and results in a number of 0.484 t $CO_2$/ t $NH_3$ and is exposed to to EU ETS1 carbon prices at €80.00/t $CO_2$, giving **€38.71** per ton of $NH_3$.

[8] https://zoek.officielebekendmakingen.nl/blg-947442.pdf