Louvain School of Management

How can Belgium develop an efficient and robust hydrogen distribution network despite market uncertainties?

Deterministic and robust approach under uncertainty inspired by Zhou's model (2024)

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Dekegel Augustin

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1 Introduction

1.1 General context

Hydrogen is undeniably emerging as a key vector in the European energy transition. To achieve its climate objectives, namely a 55% reduction in greenhouse gas emissions by 2030 and carbon neutrality by 2050, the European Union must significantly decarbonize its energy system, prioritizing efficiency and direct electrification. However, some end-uses cannot be easily electrified (such as heavy industry, long-distance transport, seasonal energy storage, ...), and low-carbon hydrogen is thus expected to become an essential alternative in these sectors. In response, the EU launched a Hydrogen Strategy in 2020, followed by the RepowerEU plan, aiming to deploy 40GW of domestic electrolysers and produce 10 million tonnes of renewable hydrogen per year by 2030, while importing an equivalent amount of green hydrogen (*Plan REPowerEU* 2022). Belgium, in line with these commitments, targets climate neutrality by 2050 and acknowledges the central role hydrogen will play in decarbonizing its industry and ensuring energy security. In 2021, Belgium became one of the first countries to adopt a national hydrogen strategy and a dedicated legal framework, appointing the gas network operator Fluxys as the manager of the future H_2 network (SPF Economie, 2022). Local production of green hydrogen is limited by the country's restricted renewable energy potential. Belgium will therefore need to import a significant share of its hydrogen via its ports of Antwerp and Zeebrugge or through interconnections with neighboring countries, in order to meet demand while reducing dependence on imported fossil fuels.

1.2 Problem

In this context, the optimal planning of a national hydrogen system raises several key questions. How can we design, by 2050, a hydrogen supply system that meets Belgium's needs at the lowest possible cost, while respecting technical, economic, and environmental constraints? Moreover, given the uncertainties surrounding the development of the hydrogen market, how can we proactively incorporate risks (notably the uncertainty of future demand) into the planning process to make the system as robust as possible? In other words, rather than planning based on a single deterministic scenario with a predefined central demand, can we propose an approach that ensures the system functions even if actual demand deviates significantly from average projections? This challenge boils down to a trade-off between cost and system resilience. A preventive oversizing may secure supply in case of high demand, but may result in underused investments if demand remains low. The objective is therefore to determine a balanced strategy in the face of these uncertainties.

1.3 Objectives

This work aims to address three main objectives. First, to develop a mathematical modeling framework of Belgium's hydrogen supply system that captures investment and operational decisions over the studied period. Second, to compare two planning approaches: initially a deterministic approach that optimizes the system for a single demand scenario, and then a robust optimization approach (Scenario-based Robust Optimization – SRO) that explicitly incorporates multiple demand scenarios to ensure decision robustness.

1.4 Methodology and structure

This research adopts a quantitative model-based approach to address the problem at hand. In particular, the study involves developing a tailored analytical model and applying it to the chosen context to evaluate its effectiveness. The research will proceed by first gathering and preprocessing the necessary data, and then implementing the model to perform the required analysis. This approach allows for a systematic examination of the research questions under controlled conditions and provides measurable evidence to support the findings. The specific details of the methodology and the model implementation are presented in Chapter 3, after a thorough review of relevant literature in Chapter 2.

1.5 Outline of thesis

The remainder of this thesis is organized as follows. Chapter 2 provides a review of the relevant literature, establishing the theoretical background and identifying gaps that motivate the research. Chapter 3 describes the research methodology in detail, including the data sources, analytical techniques, and the overall experimental design used to investigate the research questions. Chapter 4 presents the results of the study, including analysis and interpretation of the data. Finally, Chapter 5 discusses the findings, draws conclusions, and outlines the implications of the results. This final chapter also highlights the contributions of the research and offers recommendations for future work.

2 Literature review

2.1 The role of hydrogen in decarbonisation

Hydrogen is not, strictly speaking, a source of energy; rather, it is referred to as an "energy carrier". According to ADEME, the French agency for ecological transition: *"An energy carrier is a means of transporting, storing or converting energy so that it can be used for a final purpose"* (ADEME, 2021). That is, it enables the transport or storage of energy produced from other sources for deferred end use. Firstly, in industry hydrogen can replace fossil fuels as a reducing agent or high-temperature fuel for example, in the steel industry (direct reduction of iron ore) or in the production of ammonia and chemical products. In Belgium, actors such as ArcelorMittal are considering the use of hydrogen to decarbonize steel production. In the field of mobility, hydrogen is promising for heavy transport (trucks, trains, ships) and public transit (buses), particularly in cases where battery electrification is less practical due to autonomy or charging time. Fuel cell truck and hydrogen train prototypes, for instance in Germany, are currently under development. Finally, hydrogen provides a solution to the issue of the intermittency of renewable energy sources. Through electrolysis, it allows surplus renewable electricity to be stored in the form of gas during periods of high production, and then that energy can be released at a later time (Abdin et al., 2020).

It is the origin of this electrical current that will determine whether or not the hydrogen produced qualifies as low-emission hydrogen. If the initial electricity comes from a renewable source such as wind or solar power, then hydrogen will qualify as low-carbon hydrogen, otherwise known as green hydrogen. Literature often cite 3 different types of hydrogen, depending on the carbon emissions they cause. There is green hydrogen, as we have just mentioned, but also blue and grey (Choksey, 2021).

Hydrogen is classified as grey when the production methods used release greenhouse gases into the atmosphere. This grey hydrogen is currently the most mass-produced in the world because it has the lowest production costs. In contrast, green hydrogen is produced exclusively from renewable energy sources, so its production costs are much higher, making it the least used type of hydrogen. Blue hydrogen, on the other hand, falls somewhere between the 2, because the production process is the same as that used to produce grey hydrogen. The difference is that in these case systems for storing and treating the CO_2 generated during production are included in the process (CCUS and CCS). This drastically reduces its overall environmental impact but also increases its production costs (Choksey, 2021).

2.2 Hydrogen value chain organisation

Realizing a large-scale hydrogen economy requires coordinating across the entire value chain from producers to end users and building new infrastructure to connect these actors. The hydrogen value chain can be segmented into three broad stages: production, storage & distribution, and then consumption. Within each stage, different specialized players and technologies come into play.

2.2.1 Hydrogen production

Hydrogen can be produced via several pathways, most importantly through electrolysis of water using renewable electricity (yielding green hydrogen) or through steam methane reforming of natural gas (yielding grey hydrogen, or blue if coupled with CO_2 capture). Other methods include pyrolysis or using by-product hydrogen from industrial processes. Producers of hydrogen are typically energy companies or industrial gas firms investing in electrolyzer plants, reformers or other production facilities. In practice, many countries plan a mix of domestic production and imports. For instance, Belgium's domestic capacity for green hydrogen is constrained by its limited renewable electricity potential, so the country expects to import a substantial share of its hydrogen supply from abroad. Potential import routes include delivery of hydrogen or hydrogen carriers (like ammonia or methanol) via ports, as through Antwerp and Zeebrugge, or pipeline interconnections with neighboring countries. Indeed, a coalition of Belgian industry players (Engie, Fluxys and the ports) has been actively studying large-scale hydrogen imports from regions with abundant cheap renewables (e.g. Middle East, North Africa, Chile) to complement local production. In the long term, a global hydrogen trade network could emerge, but this will require significant infrastructure for shipping, storage, and conversion between hydrogen and carrier fuels.

2.2.2 Transport and distribution

Once produced, hydrogen must be transported to end users via pipelines or carriers like trucks, ships (for liquid or converted hydrogen), and rail. Pipelines are the most efficient for large-scale land transport, though safety and material issues (e.g. embrittlement) require careful retrofitting when repurposing gas pipelines (Rechrech, 2024). As pipelines are natural monopolies, hydrogen transport is managed by a Hydrogen Network Operator (HNO), akin to a TSO. The EU plans to regulate hydrogen networks similarly to gas, with third-party access and tariff rules. In Belgium, the 2021 federal strategy designated Fluxys (the gas TSO) as the future HNO (SPF Economie, 2022). Fluxys will oversee planning and operation of pipelines linking key supply and demand hubs (ports, industrial zones). By 2026, Belgium targets 100–160 km of hydrogen pipelines, backed by public funding. Local distribution systems (e.g., pipelines to refueling stations or within industrial parks) will complement the backbone. Currently, over 99% of hydrogen is used on-site, making merchant distribution a new challenge. Governments are setting standards (e.g. hydrogen purity) and building market frameworks. In Belgium, Fluxys and CREG are developing technical norms and a trading platform for hydrogen, including systems for Guarantees of Origin to certify renewable hydrogen (CREG, 2024).

2.2.3 End users

Finally, hydrogen is delivered to end-use sectors where it is utilized as a fuel or feedstock. The potential end users span multiple sectors. In industry, hydrogen will decarbonize processes in steel, chemicals (ammonia or methanol), and other high-heat applications. As a transportation fuel, hydrogen (or fuel-cell power) will be used in heavy-duty vehicles, buses, some passenger cars, trains, and potentially aviation and maritime via synthetic fuels (Rechrech, 2024). In the energy sector, hydrogen can be used for power generation (burned in turbines or used in fuel cells to supply electricity when renewable output is low) and for seasonal energy storage to back up the grid. It may also play a role in heating buildings via hydrogen boilers or blending into gas grids, although blending is generally seen as a transitional or limited solution (SPF Economie, 2022). Different end uses have different requirements: for instance, fuel cell vehicles need very high purity hydrogen; industrial uses may require reliable bulk supply at stable prices; power generation might need hydrogen on standby for peak periods. Suppliers will likely emerge to service these end-use markets. A cohesive value chain, with producers, network operators, suppliers, and consumers all coordinated is essential to scale up the hydrogen economy. Each segment must develop in tandem: production projects need confidence that transport and demand will exist, while consumers and equipment manufacturers need assurance of hydrogen availability. This has led governments to introduce integrated strategies and public-private partnerships covering the entire chain. Belgium's hydrogen strategy explicitly addresses each part of the chain, aiming to position the country as an import and transit hub (upstream), support infrastructure deployment (midstream), and create industrial demand clusters (downstream) organizing the hydrogen value chain involves establishing new infrastructure and market mechanisms so that hydrogen can flow efficiently from a growing number of production sites (including international sources) to diverse end users, with the HNO playing a central facilitating role (SPF Economie, 2022).

2.3 Planning levels

Strategic planning for hydrogen infrastructure and markets occurs at multiple levels. There is an overarching European framework, national strategies in each country, and detailed network development plans by the designated operators (HNOs). Coherence among these levels is crucial to ensure that hydrogen deployment is efficient and aligned with policy goals.

2.3.1 European level

At the European level, the EU provides direction and coordination through targets, regulations and funding initiatives. In 2020 the European Commission released its Hydrogen Strategy, setting an ambition for 40 GW of electrolyser capacity within the EU by 2030, complemented by imports of 10 million tonnes of renewable hydrogen from outside Europe. This was further reinforced by the REPowerEU plan in 2022, which accelerated targets in response to energy security concerns. The EU strategy envisions hydrogen as a key enabler for achieving the union's 2030 and 2050 climate objectives, particularly for hard-to-abate sectors. In addition to setting quantitative goals, the EU is establishing a regulatory framework for a future hydrogen market. As mentioned, the proposed Hydrogen and Decarbonised Gas Market Package will introduce EU-wide rules on hydrogen network operations, third-party access, tariff regulation and unbundling requirements similar to those for natural gas. This ensures that as national hydrogen networks emerge, they will ultimately integrate into a single European hydrogen backbone rather than isolated islands. In summary, the European level defines the vision and rules for hydrogen deployment (targets for electrolyser capacity, standards for "green" hydrogen, market rules) and provides mechanisms for member states to collaborate on a continental hydrogen infrastructure (*Plan REPowerEU* 2022).

2.3.2 National level

At the national level, individual countries craft strategies tailored to their own resources and industrial context, within the EU framework. Belgium, for instance, was one of the first EU countries to publish a dedicated National Hydrogen Strategy (SPF Economie, 2022). This strategy aligns with the EU's climate neutrality by 2050 but specifies national priorities: positioning Belgium as an import and transit hub for renewable hydrogen in Europe, leveraging its ports and industrial logistics. It also sets domestic objectives, such as having only renewable or low-carbon hydrogen in final energy consumption by 2050. In practice, that means Belgium plans a gradual ramp-up of hydrogen with increasing green hydrogen quotas over time, for example, a 60% renewable hydrogen share by 2035 and 95% by 2050 in consumption, according to strategy documents. National planning involves identifying priority projects and policies: Belgium intends to develop domestic renewable capacity (offshore wind dedicated to electrolysis), secure hydrogen import corridors, and build out a domestic pipeline backbone connecting its industrial clusters. Crucially, national governments provide support schemes to bridge the economic gap for early hydrogen projects, since green hydrogen is not yet cost competitive with fossil fuels. This can include capital subsidies, operating support (contracts for difference or carbon contracts), and quotas to create guaranteed demand. By doing so, national planning ensures that initial hydrogen supply and demand grow together domestically, preventing the classic chicken-and-egg problem.

2.3.3 Network operator level

At the network operator level, detailed hydrogen infrastructure planning is handled by the HNO, who translates EU and national targets into concrete pipeline and storage projects. In Belgium, Fluxys plans to repurpose parts of the gas grid and develop new pipelines forming a national hydrogen loop. This planning includes route design, capacity sizing, safety checks, and investment phasing. A key challenge is timing: building too early risks low asset utilization, while delays could hinder adoption. To manage this, HNOs explore mechanisms like phased expansion and tariff smoothing (e.g., regulated asset base funding). In Belgium, CREG and Fluxys have discussed co-financing or long-term tariff adjustments to protect early users. Storage is also integrated: due to unsuitable geology, Belgium will rely on alternatives like above-ground tanks or line-pack and coordinate with neighbors for seasonal storage. The HNO's development plan feeds into national policy, aligning technical execution with strategic goals. Coordination is ensured through multi-level consultation: EU policy defines frameworks, national governments set ambition, and HNOs deliver the infrastructure SPF Economie (2022) and CREG (2024).

2.4 Planning challenges for H_2 systems

The development of a large-scale national hydrogen system raises several major technical constraints. First, hydrogen storage requires dedicated infrastructure. Gaseous hydrogen has a low volumetric energy density, which necessitates either strong compression (200 to 700bar) or liquefaction (-253°C) for efficient storage, both of which involve significant energy costs and associated losses. Underground storage in salt caverns is frequently cited as a promising solution for storing large volumes of hydrogen over the long term, by analogy with natural gas storage in similar structures. This is one of the most promising technical options for large-scale storage, as salt caverns provide sealed, high-pressure-capable volumes. However, this technology remains at an experimental stage for hydrogen and is unlikely to be available at full industrial scale for some time. In the meantime, on-site storage (pressurized steel tanks) or near-site solutions (small-scale caverns) may be used, albeit with more limited capacities (*Stockage d'hydrogène en cavités salines* 2025).

Next, the conversion of energy into and from hydrogen involves incomplete efficiencies. Water electrolysis currently achieves an efficiency of approximately 65 to 70% (LHV – Lower Heating Value) for commercial technologies, meaning that around one third of the input electricity is lost as heat. The reconversion of hydrogen into electricity via a fuel cell or gas turbine also yields efficiencies of about 50 to 60%. As a result, the overall "Power-to-H_2-to-Power" cycle returns at best 30 to 40% of the initial electricity, which justifies reserving hydrogen for end uses where no more efficient alternative is available (Abdin et al., 2020). Finally, the intermittency of renewable sources (solar and wind) directly impacts green hydrogen production: high variability in electricity supply may lead to low capacity factors for electrolyzers or require oversizing of production assets to ensure sufficient annual output. Planning must therefore account for the temporal variability of both supply and demand, and dimension the system accordingly for worst-case scenarios. Intermittency management can be mitigated by combining multiple renewable sources and geographically distributing production (Zhou et al., 2024).

The second category of challenges concerns economic constraints. Hydrogen infrastructure involves very high capital expenditures (CAPEX), whether for electrolyzers, reforming plants with carbon capture, new pipelines or the conversion of existing ones, port terminals,.... The development of these assets is spread over several years and their profitability remains uncertain as long as the customer base is limited. As explained by Laurent Remy (2025), launching a hydrogen network requires investing hundreds of millions of euros in pipelines that, at first, will serve only one or two clients. Under a standard tariff regime, this would impose prohibitive transport costs on these early adopters. Support mechanisms and intertemporal cost allocation schemes such as long-term tariff smoothing or public subsidies are therefore being considered to mitigate this risk and avoid having to wait until all consumers are ready before building the network (Laurent Remy, 2025).

Beyond CAPEX, operational costs (OPEX) represent a major challenge: the cost of renewable electricity directly determines the price of green hydrogen. Today, producing 1kg of H_2 via electrolysis requires approximately 50kWh of electricity; at 60€/MWh, this amounts to 3€/kg for electricity alone, not including electrolyzer amortization or labor costs placing green hydrogen well above the 1–2€/kg range of grey hydrogen. The cost of natural gas and CO_2 will influence the competitiveness of blue hydrogen: if gas prices are high and carbon pricing is strict, blue hydrogen will lose its economic advantage (*Global Hydrogen Review 2024 – Analysis* 2024). Furthermore, the competition between domestic hydrogen production and the import of hydrogen or its derivatives such as ammonia or methanol will be decisive. Imports may reduce the need for local infrastructure investment and allow access to lower production costs abroad, but they entail conversion costs (e.g., liquefaction or transformation into ammonia) and transport expenses. According to some estimates, importing hydrogen by ship in the form of reconverted ammonia could cost around 4€/kg by 2030, which remains above the expected cost of domestic blue hydrogen and only marginally competitive with green hydrogen produced locally from offshore wind assuming high capacity factors offset electricity costs. Finally, a hydrogen system will need to integrate into the broader energy market: CO_2 pricing, taxes, and support mechanisms will significantly affect the profitability of different production pathways. Planning must therefore incorporate these uncertain and potentially evolving economic parameters (CREG, 2024).

Planning choices are strongly shaped and constrained by environmental and regulatory requirements. The European Union has defined strict criteria for renewable hydrogen: starting in 2030, a significant share of the hydrogen used in industry and transport must be of renewable origin, with a figure of 42% cited for industrial use in 2030 (Laurent Remy, 2025). Belgium is logically aligning itself with these objectives: its hydrogen strategy stipulates that only renewable energy sources will be included in the final energy mix by 2050 and ideally much sooner (SPF Economie, 2022). In practice, this translates into gradually increasing quotas for green hydrogen that must be met. In our modelling, for instance, we assume that by 2050, 95% of hydrogen consumption will come from renewable sources, compared to 60% in 2035, reflecting the progressive decarbonization imperative outlined in European roadmaps. These constraints create a framework that strongly shapes planning decisions. From an environmental perspective, it is also necessary to consider the local acceptability and footprint of infrastructure such as H_2 pipelines, which, in certain areas, may face opposition (e.g., the hydrogen backbone project challenged in Flanders due to concerns about the groundwater table). Similarly, the construction of large-scale wind turbines to power electrolyzers or the conversion of gas terminals for imported ammonia comes with its own impacts and regulatory constraints. All of these factors must be incorporated into the overall vision to avoid a purely techno-economic plan running into environmental or societal barriers (Laurent Remy, 2025).

2.5 Optimization models for energy systems under uncertainty

Long-term energy planning traditionally relies on optimization models that help identify, among a wide range of technological options, the combination that minimizes a given cost or maximizes a given benefit, subject to constraints. Many reference models use linear programming (LP) or mixed-integer linear programming (MILP) to formulate the planning problem. For example, MARKAL/Times-type models represent energy supply over several decades through a linear program that minimizes discounted costs, subject to demand satisfaction and resource limitations (Li, H. Manier, and M.-A. Manier, 2019). These linear models offer the advantage of relatively efficient solving, even for large systems, thanks to powerful mathematical solvers, and they guarantee global optimality (unlike heuristic approaches). Linearity is achieved by simplifying certain relationships, meaning no variable efficiencies and no nonlinear costs, while allowing fractional technology shares. When discrete choices are needed (e.g., whether or not to build a new plant, or selecting a pipeline from a few standardized sizes), MILP models are used by introducing binary variables. This increases computational complexity (an NP-hard problem), but for limited national-scale problems, the models remain solvable within reasonable timeframes, especially when appropriate decomposition techniques or simplifications are applied (Li, H. Manier, and M.-A. Manier, 2019).

The major challenge lies in the integration of uncertainties into these models. Two main approaches dominate the literature: stochastic optimization and robust optimization. Stochastic optimization models uncertainties through a set of probabilistic scenarios; it generally aims to minimize the expected cost or maximize expected utility while accounting for the possibility of multistage decision-making (with "here-and-now" decisions made before the uncertainty is revealed, and subsequent "wait-and-see" decisions made afterward). This approach yields solutions that are optimal in expectation and can be refined to account for risk. However, it requires reliable estimation of scenario probabilities and may lead to fragile solutions that become unacceptable if an unfavorable scenario occurs, such as a hydrogen shortage in the event that demand turns out to be significantly higher than the average (Li, H. Manier, and M.-A. Manier, 2019). Robust optimization, as described in Zhou et al. (2024), follows a different philosophy. It aims to find a solution that remains feasible for all realizations within a predefined uncertainty set, by minimizing the cost in the worst-case scenario. In other words, it does not rely on probabilities but instead defines a range of possible variations (e.g., assuming that H_2 demand may vary by $\pm 30\%$ around the central trajectory), and identifies the configuration that performs best under the most adverse scenario within that domain. The robust approach has the advantage of guaranteeing immunity to variations within the specified range: the robust solution will always satisfy constraints even under the most extreme conditions. However, it can lead to very conservative (over-dimensioned) solutions if the uncertainty set is broad, as the minimized cost is dominated by the worst-case outcome. In summary, energy planning under uncertainty relies on a broad methodological arsenal. The choice of approach depends on the context: when uncertainties can be reliably modelled using probabilities, stochastic programming offers an elegant solution, but in cases involving deep uncertainty or stringent safety criteria, the robust approach is often preferred for its conservative nature.

Another important aspect is the temporal granularity of the models. Accurately representing an energy system requires capturing intra-annual fluctuations such as seasonal patterns and day–night cycles, as these determine flexibility and storage needs. However, using an hour-by-hour resolution over 8,760 hours per year across 30 years is computationally prohibitive in an investment planning model. As a result, most models adopt some form of temporal aggregation: either through longer time steps (quarterly, monthly, seasonal), or through representative days or weeks (a limited set of typical profiles reflecting annual variability). The appropriate level of detail must be selected based on the specific problem being studied (Li, H. Manier, and M.-A. Manier, 2019). For example, in a hydro–wind system, weekly and seasonal variability is critical (due to storable water versus intermittent wind) and requires at least a monthly resolution. In a hydrogen system, if the objective is to size seasonal storage, a minimum summer/winter distinction is needed to evaluate the transfer of summer surpluses to winter consumption. Conversely, detailing the 24 hours of a day is only relevant if the hydrogen system is also being used to provide daily flexibility for the power grid. In our case, we adopt a simplified two-season representation (summer/winter) for each future time horizon. This allows us to differentiate between a lower demand profile in summer and a higher one in winter (assuming, for instance, increased use of H_2 for heating or backup electricity generation during winter) and to model seasonal storage (storing in summer for use in winter). This reduced granularity keeps the problem tractable while still capturing the main seasonal effects (Zhou et al., 2024). In the study by Zhou et al. (2024), which we will primarily follow in this thesis, a detailed multi-period spatio-temporal resolution was explored using decomposition methods. This demonstrates that with advanced algorithms, it is possible to move toward higher granularity. Nevertheless, in the context of this thesis, we will prioritize the simplicity and transparency of the model, while acknowledging that further temporal refinements could enhance the analysis.

2.6 The Zhou et al. (2024) study

The study by Zhou et al. (2024) serves as the main methodological reference for this thesis. The authors focus on the optimal planning of a hydrogen network in Great Britain at the regional scale under uncertainty regarding future demand. Their model, formulated as a mixed-integer linear program, is spatially explicit, meaning it considers multiple regions for production, consumption, and transport infrastructure. It is also multi-period, accounting for several time stages up to 2050. The objective is to minimize the total cost of the hydrogen system (investment and operation) while satisfying regional demand in each period. A key feature of the model is the integration of demand uncertainty through a robust optimization approach. More specifically, Zhou et al. (2024) define a set of demand scenarios low, central, and high for each future period, reflecting different possible trajectories (e.g., depending on how rapidly hydrogen adoption spreads in industry and transport). Rather than assigning probabilities and optimizing in expectation, they adopt a robust optimization approach based on these scenarios. That is, they seek the infrastructure configuration that minimizes cost in the worst-case scenario while remaining feasible across all scenarios. This approach, referred to by the authors as “data-driven robust optimization”, is justified by the critical nature of hydrogen supply security: the aim is to avoid a situation in which the constructed plan proves inadequate if demand exceeds the average forecast. In other words, a slightly higher cost is accepted to safeguard against adverse outcomes.

Zhou et al. (2024) structure their analysis by comparing the robust solution with those obtained through a classical deterministic or stochastic approach. They show that robust planning leads to slightly higher investments in capacity, particularly in production, in order to meet the high-demand scenario without shortages. For example, in their case study, the robust solution invests more in electrolyzers and transport infrastructure than the deterministic solution based on average demand, resulting in a moderate cost increase but ensuring that no region faces a hydrogen shortage, even in the event of a strong demand surge. In terms of scenarios, Zhou et al. (2024) generally consider three trajectories (low, central, and high) constructed from demand projections drawn from the literature or expert input. The low scenario may reflect limited hydrogen uptake (e.g., if alternative technologies develop more rapidly or certain industrial projects do not materialize), while the high scenario represents an ambitious deployment (e.g., stronger policy support or innovations that rapidly reduce hydrogen costs). In their paper, the authors mention the use of scenario reduction methods to limit the number of scenarios while preserving diversity among cases, in order to maintain computational tractability.

The SRO (Stochastic Robust Optimization) approach implemented by Zhou et al. (2024) is distinctive in that it combines elements of here-and-now planning with adjustable decisions. In a multi-period context, one can envision making initial investment decisions that are robust, while retaining some flexibility to adjust future expansions based on the actual demand observed at the beginning of each period. Zhou et al. (2024) address this through a two-stage model with recourse, using a two-stage adjustable robust optimization framework (Brenner et al., 2025). However, the combinatorial complexity introduced by this framework is substantial, which is why the authors propose a decomposition scheme to solve the resulting large-scale problem. The results presented by Zhou et al. (2024) emphasize that the robust approach yields a more cautious solution that avoids shortages in extreme scenarios, at the cost of only a slightly higher total system cost compared to the deterministic solution. In other words, the "insurance cost" against adverse outcomes appears relatively low, as the additional infrastructure built for robustness, i.e., overcapacity, still proves useful in the central scenario part of the time (for instance, to export surplus hydrogen or to relieve stress on the system during peak periods).

In summary, the study by Zhou et al. (2024) provides the following key insights. First, explicitly integrating uncertainty scenarios into the objective function steers planning toward more resilient solutions. Second, the cost difference between a robust and a non-robust solution is relatively moderate in the case of hydrogen, as assets sized for the worst-case scenario can often operate at partial load under lower demand conditions, thereby smoothing the economic impact. Finally, robustness avoids "regret" investments that could prove insufficient and offers valuable strategic flexibility. These findings support the relevance of applying a similar approach to the planning of the Belgian hydrogen system.

2.7 Positioning of my master's thesis

This thesis draws methodologically from Zhou et al. (2024), who developed a robust optimization model for hydrogen infrastructure planning under demand uncertainty in Great Britain. While Zhou's framework is advanced in terms of spatial and temporal granularity and uncertainty treatment, it was designed for the UK context and lacks applicability to different regulatory, spatial, and policy settings.

This work adapts the core strengths of Zhou et al. (2024) model particularly its robust optimization formulation, capacitated network design, and seasonal storage integration but tailors them to the Belgian context. The hydrogen system in Belgium differs structurally: it involves cross-border infrastructure coordination, limited domestic production, no geological storage potential, and a nascent HNO (Fluxys) with evolving regulatory mandates. In contrast to Zhou's multi-node model with hourly time resolution, this thesis uses a simplified seasonal framework with national spatial aggregation to reflect Belgium's smaller scale and available data.

Rather than directly replicating Zhou et al. (2024) setup, the model developed here synthesizes existing modeling principles into a form that supports national policy decisions. It integrates Belgium-specific constraints such as green hydrogen quotas, storage mandates, and border flows. The result is not a replication, but a context-sensitive adaptation of existing methods to answer policy-relevant questions for Belgium's hydrogen rollout.

3 Modelling

3.1 Scope of the model

The model we develop aims to provide an aggregated representation of Belgium's hydrogen supply system over the 2035-2050 period. The assumptions and scope adopted are as follows:

3.1.1 Unified national approach

The Belgian territory is modeled as a single zone, with no internal geographic subdivisions. In other words, we do not differentiate between regions or explicitly model a pipeline network within the country. This implies an assumption of perfect internal hydrogen transport fluidity: any hydrogen produced anywhere in Belgium can be delivered to any consumption point domestically. This simplification is justified by Belgium's modest size and by Fluxys's plans to deploy a comprehensive "multi-molecule" transmission network connecting all major industrial hubs (Laurent Remy, 2025). The model thus optimizes aggregate quantities of hydrogen to produce, import, or store, rather than determining specific pipeline routes

3.1.2 Aggregated and non-sectorised demand

Total hydrogen consumption is represented by an aggregate annual demand (in TWh) to be satisfied. No distinction is made between hydrogen for industry, mobility, or electricity generation, even though these segments may, in reality, have different consumption profiles and quality requirements. The decision not to disaggregate demand is justified by the goal of simplicity and by the fungible nature of hydrogen meaning that regardless of its final use, an H_2 molecule remains identical and can be distributed through the same network (with the exception of purity considerations for industry, which are not modeled here). The demand projections used originate mainly from the industrial sector and heavy-duty mobility, which are expected to account for the bulk of volumes between 2035 and 2050 (SPF Economie, 2022).

3.1.3 2035 and 2050 horizons

Two representative years, 2035 and 2050, are considered, for which investment and supply decisions are modeled. These two years are treated as "snapshots" in the model. They correspond to two key stages: 2035 represents a near-term future in which the hydrogen ecosystem begins to be deployed (this choice of year aligns with the objective of having an operational network by 2026 and a scale-up throughout the 2030s) and 2050 corresponds to the mature state of a carbon-neutral system (SPF Economie, 2022). No intermediate years are explicitly simulated. In modeling terms, this means that we determine the installed capacities required for 2035 and those for 2050 simultaneously, without modeling the transition path between them. In the base version of the model, there is no direct inheritance link between 2035 and 2050 (in other words, the 2050 capacity is not required to be greater than or equal to that of 2035; each horizon is optimized independently based on its own needs). Although this assumption may appear counterintuitive (since infrastructure built in 2035 could still be in use by 2050), it was initially made to simplify the resolution and because the model does not incorporate investment trajectory dynamics. That said, we will discuss in the conclusion the implications of this simplification and the possibility of relaxing it.

3.1.4 Two seasons (summer/winter)

Each year is divided into two periods representing summer and winter. The aim is to capture the seasonality of both demand and production. We assume that X% of annual demand occurs in summer and (100–X)% in winter, reflecting, for instance, higher heating or backup electricity needs during the winter months. Similarly, the renewable generation potential (which feeds electrolyzers) is split across the two seasons. These fractions are parameterized. The advantage of this binary seasonal approach is that it enables the modelling of seasonal storage: the model is allowed to store hydrogen during summer (when excess production may occur) and release it in winter (when demand exceeds production). Technically, this results in a seasonal storage balance constraint. However, we do not introduce a finer temporal resolution (e.g., daily peaks), which implies that intra-seasonal flexibility (e.g., day/night fluctuations) is assumed to be either manageable by other means or not necessary to simulate explicitly for capacity planning purposes. The seasonal scale is considered appropriate because hydrogen's main value lies in its ability to provide inter-seasonal storage, whereas batteries are more suited for managing daily intermittency (CREG, 2024).

3.1.5 Modelled technologies

The model includes two domestic hydrogen production pathways: water electrolysis representing green hydrogen, and natural gas reforming with carbon capture (SMR_CCS) representing blue hydrogen. These two options correspond to the main levers identified in the Belgian hydrogen strategy. Local green hydrogen production is constrained by the renewable energy potential, while blue hydrogen can serve as a transitional bridge Laurent Remy (2025) and SPF Economie (2022). On the storage side, we model an aggregated hydrogen storage option without specifying the underlying technology (this could represent a set of above-ground tanks or a salt cavern). This storage is characterized by a maximum capacity (in TWh), a round-trip efficiency, and associated costs (CAPEX per TWh of capacity and OPEX per TWh per year). We also include the possibility of importing hydrogen from abroad, up to a certain limit (reflecting, for instance, import capacity via ports or international pipelines). In the model, imports are represented as seasonal decision variables (in TWh), subject to an annual upper bound (which differs between 2035 and 2050). Imports do not incur investment costs, as port and pipeline infrastructure is assumed to be out of scope or embedded in the variable cost, but they are subject to a variable cost per TWh imported, reflecting the purchase price on the international market. Finally, the total hydrogen demand in Belgium (in TWh) is an exogenous parameter of the model for both 2035 and 2050, based on the defined scenarios.

3.2 Data sources and parameters

Accurate and consistent data are crucial for calibrating the model. All input parameters have been sourced from recognized studies, reports, and expert input to ensure realistic scenarios. In particular, data were gathered from government publications, academic or industry reports and were supplemented with assumptions validated through an expert interview (Laurent Remy, 2025). Key parameters and their values for the Belgian case are summarized below (for both 2035 and 2050 horizons):

3.2.1 Hydrogen demand

As noted in Section 3.1, the central scenario annual demand is set to 25 TWh in 2035 and 50 TWh in 2050. These figures are grounded in official projections for a climate-neutral pathway. The value for 2050 (50 TWh) aligns with the order of magnitude suggested by the European Parliament for Belgium's hydrogen needs in a net-zero scenario European parliament (2021) and is slightly conservative relative to the national hydrogen strategy's vision (SPF Economie, 2022). The 2035 demand (25 TWh) comes from intermediate forecasts CREG (2024) and expert judgment from Fluxys (Laurent Remy, 2025). These demands are treated as exogenous inputs that the system must meet. Within each year, demand is divided into seasons: 40% in Summer and 60% in Winter (i.e. demand_2035,summer $\approx$ 10 TWh and demand_2035,winter $\approx$ 15 TWh; for 2050, 20 TWh summer, 30 TWh winter). This 40/60 seasonal split is a simplifying assumption reflecting likely higher consumption in winter (due to heating and peak electricity generation needs) and relatively lower summer demand. It is inspired by scenarios where hydrogen is used for winter power generation and blended into heating gas (SPF Economie, 2022). In the absence of detailed monthly profiles, this split provides a reasonable approximation of seasonal variation.

3.2.2 Renewable energy availability

An important exogenous factor is the domestic renewable electricity potential dedicated to hydrogen production. We assume that there is a maximum amount of renewable electricity that can be allocated to electrolyzers each year, due to limits in renewable generation capacity (solar and wind) and competing uses of that electricity. Based on Belgian energy outlooks, we set a limit of 40 TWh/year in 2035 and 80 TWh/year in 2050 as the total renewable electricity available for hydrogen production. In other words, in 2050 the model cannot produce more green hydrogen than what 80 TWh of renewable electricity input would allow (and similarly 40 TWh cap in 2035). This effectively bounds domestic green hydrogen supply. Furthermore, this annual renewable potential is divided by season. For instance, out of 40 TWh/year in 2035, a certain percentage is assumed available in summer vs. winter (e.g. 45% in summer, 55% in winter), reflecting that solar-heavy generation yields more output in summer, whereas wind is more evenly spread (CREG, 2024). For the 80 TWh in 2050, we similarly distribute a portion to summer (e.g. 45%) and the rest to winter. These fractions allow the model to capture that even renewable production has seasonal variability. Any attempt by the model to produce green hydrogen beyond these limits in a season will be constrained (this is imposed later in the constraints). Essentially, this parameter reflects Belgium's limited renewable potential, the country cannot produce unlimited green hydrogen due to finite wind/solar resources and must import or use gas if demand exceeds this green supply (CREG, 2024).

3.2.3 Electrolyzer (Green H_2)

Capital investment cost (CAPEX) is assumed to be about €1.275 million per MW of hydrogen output capacity (for the 2030–2035 timeframe). This figure is based on projected costs for alkaline/PEM electrolyzers *Belgium as a hydrogen importhub, roadmap towards 2030 and beyond* (2025) and is in line with IEA estimates for early 2030s installations. For simplicity, we use a similar order of magnitude for both 2035 and 2050 in the model, though in reality costs in 2050 could be lower. The fixed O&M cost for electrolyzers is taken as 3% of the CAPEX per year (*Global Hydrogen Review 2024 – Analysis* 2024). This is a typical assumption of *CleanH2ProductionPathwaysReport* (2025) covering maintenance and other fixed running costs. The conversion efficiency of electrolysis is set at 70% (LHV), meaning 1 unit of hydrogen energy requires roughly $1/0.7 \approx 1.43$ units of electrical energy. This corresponds to an efficiency typical for modern electrolyzers. We also account for the variable cost of operating electrolyzers, which is essentially the cost of electricity. For 2035, we assume an electricity price of €60/MWh, and for 2050, €45/MWh, anticipating cheaper renewable electricity in the long term (e.g. due to expanded solar capacity and battery storage smoothing out prices). These values are aligned with scenarios in which renewables become very inexpensive by mid-century (European parliament, 2021). In the model, the electricity cost translates to a variable hydrogen production cost for electrolyzers.

3.2.4 SMR with CCS (Blue H_2)

For Steam Methane Reforming with carbon capture, we assume a CAPEX of around €1.0 million per MW_H_2 of capacity. This cost includes the CO_2 capture unit and is based on studies of large-scale SMR_CCS deployment (*Charting pathways to enable net zero* 2021). The efficiency of the SMR_CCS process is assumed to be 65% (energy content of hydrogen output vs. methane input). We do not explicitly model the natural gas supply, assuming it is readily available as needed (with costs captured in the variable OPEX). The variable production cost for SMR_CCS is estimated at €1.2 per kg H_2 (excluding carbon costs). This is roughly equivalent to €36 million per TWh_H_2 and corresponds to the operational cost. On top of this, producing hydrogen from methane emits CO_2 (even with capture, there are residual emissions). We assume about 3.4 kg CO_2 emitted per kg H_2 (i.e., a 90% capture rate from a baseline of 34 kgCO_2/kgH_2 for unabated SMR). A carbon price of €150 per ton CO_2 is considered for accounting purposes, which would add roughly €0.51 per kg H_2 in effective cost if the emissions were monetized. In our model, however, we handle the CO_2 impact via an emissions constraint rather than adding it directly to the cost. In summary, we set the blue hydrogen variable cost in the model to 36 M€/TWh (covering gas and non-CO_2 operational costs) and separately limit the quantity of blue H_2 via an emissions cap.

3.2.5 Hydrogen storage

We assume the availability of a large-scale hydrogen storage option with a capital cost of €400 per kg of H_2 capacity . This is equivalent to €0.4 million per ton of H_2 or about €12,000 per MWh of energy storage (since 1 ton $H_2 \approx 33$ MWh). This figure represents high-pressure steel tank storage costs, which are relatively expensive; it's a high-end estimate meant to be conservative (*Stockage d'hydrogène en cavités salines* 2025). Cheaper storage methods like salt caverns are not considered feasible in Belgium's geology, so we use the tank storage cost as a proxy. The fixed O&M cost for storage is taken as 1% of CAPEX per year, i.e. about €4 million per TWh capacity per year. We also assume a round-trip efficiency of 95% for stored hydrogen, meaning that for each 1 TWh put into storage, 0.95 TWh can be retrieved (5% losses due to compression and leakage). The storage has a maximum energy capacity denoted cap_max_store. To ensure this never binds artificially, we set cap_max_store to a high value (on the order of the upper physical potential for hydrogen storage in Belgium). For example, in our baseline we use cap_max_store $\approx$ 7 TWh, which corresponds to roughly 210,000 tons of hydrogen. An extremely large storage volume that would not be economically reached in optimal solutions. This effectively means storage capacity in the model is only limited by economics (cost) rather than an arbitrary cap, unless otherwise specified (CREG, 2024).

3.2.6 Green hydrogen quota

To ensure a minimum level of renewable hydrogen usage, we set a quota_vert parameter requiring at least 60% of hydrogen demand in 2035 to be met by green hydrogen, and 95% in 2050. These quotas are inspired by European ambitions for renewable fuels of non-biological origin (RFNBO) and the Belgian hydrogen strategy's goals. The 60% in 2035 allows for a transition period where blue H_2 can cover up to 40% of demand, whereas by 2050 the intention is that nearly all hydrogen should be renewable. The model will enforce these minima (e.g. in 2050, electrolytic $H_2 \geq 0.95$ * total H_2 demand) (*Belgium as a hydrogen importhub, roadmap towards 2030 and beyond* 2025).

3.2.7 CO_2 emissions cap

Alongside the green quota, we impose an absolute CO_2 emission limit on hydrogen production. Based on Belgium's carbon budgets, we assume a maximum of about 2.5 million tonnes CO_2 in 2035 and 1.5 million tonnes in 2050 can be emitted from hydrogen production. These caps ensure that even if some blue hydrogen is used, the emissions do not exceed what is deemed acceptable in those years (SPF Economie, 2022). The figures roughly correspond to the emissions that would result if blue hydrogen provided the non-green share under the quota (with our assumed capture rate and demand levels). The model's emission constraint will utilize these values to limit SMR hydrogen output.

All the above data inputs are compiled in an Excel data file (Data – H2.xlsx) linked to the model. The use of a centralized data table makes it easy to update values or test different scenarios by changing these parameters. Units are carefully handled, for example, costs given by sources in €/kg are converted to €/TWh for use in the model. These conversion factors (such as 1 kg H_2 = 0.0000333 TWh) and assumptions (like LHVbased energy content) are the same as described above, ensuring consistency in the model's dimensional analysis. In the next section, we present the mathematical model formulation that uses these parameters and assumptions to determine the optimal hydrogen supply strategy.

3.3 Model formulation

3.3.1 Decision variables

- $CapProd_{p,y}$: installed hydrogen production capacity for technology p (Electrolyzer or SMR_CCS) at time horizon y (2035 or 2050), expressed in MW. This represents the maximum production power (i.e., hydrogen energy output per unit of time). It is assumed that the installed capacity at each horizon is newly built for optimization purposes (no aging or phasing between 2035 and 2050 is considered, as previously explained). We have $p \in \{\text{Electrolyzer}, \text{SMR\_CCS}\}$ and $y \in \{2035, 2050\}$.

- $CapStore_y$: installed hydrogen storage capacity (in TWh) for year y. This represents the maximum amount of hydrogen energy that can be stored at a given time. It can be interpreted as the volume of a salt cavern or the aggregate capacity of available storage tanks.

- $Prod_{p,y,s}$: volume of hydrogen produced by technology p during season s of year y, expressed in TWh. The seasons s are Summer and Winter. For example, $Prod_{\text{Electrolyzer, 2035, Summer}}$ represents the TWh of green hydrogen produced during summer 2035. For simplicity, production is assumed to be "uniformly distributed" over the season, so that the capacity constraint (see constraint section) links $Prod$ and $CapProd$ linearly.

- $Import_{y,s}$: volume of hydrogen imported from abroad during season s of year y, expressed in TWh.

- $StoreIn_{y,s}$ and $StoreOut_{y,s}$: amounts of hydrogen (in TWh) respectively injected into storage (charging) and withdrawn from storage (discharging) during season s of year y. For example, $StoreIn_{2035,\text{Summer}}$ represents the surplus hydrogen in summer 2035 that is stored instead of being consumed immediately, while $StoreOut$ typically corresponds to the quantity released in winter 2035 to help meet demand.

- $StockLevel_{y,s}$: level of hydrogen stock available at the end of season s in year y, expressed in TWh. In other words, this represents the amount of hydrogen remaining in storage at the end of Summer or Winter.

All these variables are continuous and lower-bounded by 0 (no negative quantities). There is no explicit variable for exports, final consumption, or losses these elements will be incorporated within the model constraints.

3.3.2 Parameters

- $demand_{y,s}$: hydrogen demand to be met during season s of year y, expressed in TWh. These values are calibrated such that $demand_{y,\text{Summer}} + demand_{y,\text{Winter}}$ = total annual demand for year y.

- $capex\_prod[p]$: unit investment cost for production technology p, in €/MW. For example, $capex\_prod[\text{Electrolyzer}] \approx 1{,}275{,}000/\text{MW}_{\text{H}_2}$ in 2030–2035 according to the IEA, which includes the installation costs of alkaline or PEM electrolyzers. For $p =$ SMR_CCS, a CAPEX of approximately 1 million€ per MW_{H_2} is used (this cost includes the carbon capture unit).

- $opex\_prod[p]$: fixed annual operation and maintenance cost for technology p, in €/MW/year. This cost represents the yearly expenditures associated with installed capacity (e.g., electrolyzer maintenance). For electrolyzers, we assume a fixed OPEX of approximately 3% of the CAPEX. For SMR_CCS, fixed costs are considered negligible and can be included in the variable cost instead.

- $capex\_store$: investment cost for hydrogen storage, in €/TWh of storage capacity. This value is highly uncertain; we assume 400€/kg for pressurized storage, equivalent to 400k€/t, which results in 400×10^6/TWh, or approximately 13.3€ per kWh of capacity. This cost can represent, for example, the construction of a salt cavern. It is a high-end estimate (non-binding assumption, as the optimal capacity will not reach the upper bound).

- $opex\_store$: annual maintenance cost for hydrogen storage, in €/TWh/year. We assume 1% of the CAPEX, which corresponds to approximately 4×10^6/TWh/year.

- cap_max_store: physical maximum storage capacity, in TWh. This can be set to a high value so as not to constrain the solution (e.g., 7TWh in our baseline data, corresponding to approximately 210,000tons, a high-end assumption).

- $eff\_prod[p]$: conversion efficiency of production technology p. For electrolyzers, $eff\_prod[\text{Electrolyze}$ 0.7 (70% LHV), meaning that producing 1 TWh of H_2 requires 1/0.7 = 1.43 TWh of electricity input. For SMR_CCS, an efficiency relative to gas energy could be defined, but since gas supply is not explicitly modeled, this parameter is of limited use (we implicitly assume sufficient gas availability, and the gas + capture cost is embedded in the variable cost).

- $cost\_import$: cost of hydrogen import, in €/TWh. This is the unit cost per TWh of imported hydrogen. A value of 4 €/kg corresponds to 120 million €/TWh. We use $cost\_import = 120{,}000{,}000/\text{TWh}$.

- $opex\_var[p, y]$: variable production cost (€/TWh of H_2 produced) for technology p in year y. For electrolyzers, this corresponds primarily to electricity cost: for example, 60 €/MWh in 2035 and 45 €/MWh in 2050. For SMR_CCS, the variable cost includes natural gas, operational expenses, and the cost of residual CO_2 emissions. We estimate the base operating cost at approximately 1.2 €/kg of H_2 (excluding CO_2), i.e., 36 million €/TWh. The carbon cost can be added separately: with 3.4 kgCO_2/kg H_2 emitted and a carbon price of 150 €/t, this results in an additional 0.51 €/kg. In the implemented model, the CO_2 price component is handled via a constraint rather than embedded in the cost, so we set $opex\_var[\text{SMR}] = 1.2/\text{kg}$ = 36M€/TWh, and manage emissions separately.

- $limit\_import\_y$: annual import limit for year y, in TWh/year.

- $quota\_vert\_y$: minimum fraction of annual demand in year y that must be covered by green hydrogen (Electrolyzer). We set $quota\_vert_{2035} = 60\%$ and $quota\_vert_{2050} = 95\%$. These quotas reflect the European RFNBO ambition while allowing transitional use of blue hydrogen in 2035.

- $seuilCO_2\_y$: CO_2 emission threshold for year y.

- $stockSec_y$: strategic security stock required at the end of summer in year y, expressed in TWh. By analogy with mandatory natural gas storage policies (e.g., EU rule of 90% filling by November 1st), we impose that a minimum volume of H_2 remains in storage at the end of summer to hedge against winter peaks or supply disruptions. We assume a security stock corresponding to approximately one month of estimated consumption.

3.3.3 Objective function

Now that the variables and parameters have been defined, we can formulate the objective function of the deterministic model.

$$
\begin{aligned}
\min \quad Z = & \sum_{p\in P}\sum_{t\in T} \text{capex\_prod}[p] \cdot \text{CapProd}_{p,t} + \sum_{t\in T} \text{capex\_store} \cdot \text{CapStore}_t \\
& + \sum_{p\in P}\sum_{t\in T} \text{opex\_prod}[p] \cdot \text{CapProd}_{p,t} \\
& + \sum_{p\in P}\sum_{t\in T} \text{opex\_var}[p,t] \cdot \text{Prod}_{p,t} \\
& + \sum_{t\in T} \text{opex\_store} \cdot \text{CapStore}_t \\
& + \sum_{t\in T} \text{cost\_import} \cdot \text{Import}_t
\end{aligned} \tag{1}
$$

This objective function represents the total annual cost (in €) for the two considered years, aggregated without discounting. Since we do not model multi-year investments, we simply sum the costs for 2035 and 2050. To obtain a fully discounted total cost, one would need to discount the 2050 cost back to 2035 and potentially include an end-of-horizon or decommissioning term but this would unnecessarily complicate the model for the purpose of relative scenario comparison.

- $capex\_prod \cdot CapProd$: investment cost in production capacities, for each technology and each time horizon.
- $opex\_prod \cdot CapProd$: annual fixed operation and maintenance (O&M) costs associated with these capacities.
- $capex\_store \cdot CapStore$: investment in hydrogen storage.
- $opex\_store \cdot CapStore$: storage maintenance costs.
- $opex\_var \cdot Prod$: variable production cost (electricity for electrolysis and gas for SMR), proportional to the quantity produced each season.
- $cost\_import \cdot Import$: purchase cost of imported hydrogen.

3.4 Model constraints

Mathematical Formulation of Constraints

3.5 Model constraints

Mathematical Formulation of Constraints

$$Prod_{p,y,s} \leq CF \times MW\_to\_TWh \times CapProd_{p,y} \tag{C1}$$

$$\sum_p Prod_{p,y,s} + Import_{y,s} + StoreOut_{y,s} = demand_{y,s} + StoreIn_{y,s} \tag{C2}$$

$$StockLevel_{y,s} \leq CapStore_y \tag{C3}$$

$$CapStore_y \leq cap\_max\_store \tag{C4}$$

$$\sum_s Prod_{\text{Electrolyser},y,s} \geq quota\_vert_y \times \sum_s demand_{y,s} \tag{C5}$$

$$Prod_{\text{Electrolyser},y,s} \leq potentiel\_ENR_{y,s} \tag{C6}$$

$$\sum_s Import_{y,s} \leq limit\_import_y \tag{C7}$$

$$\frac{1}{1000}\left(\sum_s \frac{Prod_{\text{SMR\_CCS},y,s}}{KG\_TO\_TWH}\right) \times EF \leq seuilCO_{2y} \tag{C8}$$

$$StockLevel_{y,\text{été}} = StoreIn_{y,\text{été}} - StoreOut_{y,\text{été}} \tag{C9}$$

$$StockLevel_{y,\text{hiver}} = StockLevel_{y,\text{été}} + StoreIn_{y,\text{hiver}} - StoreOut_{y,\text{hiver}} \tag{C10}$$

$$StockLevel_{y,\text{été}} \geq stockSec_y \tag{C11}$$

Description of Constraints

- **(C1) Production capacity constraint:** ensures that seasonal production does not exceed the technical production potential, considering the capacity factor and conversion between MW and TWh.
- **(C2) Demand satisfaction constraint:** balances all inflows (production, import, withdrawal) and outflows (demand, injection) of hydrogen within each season.
- **(C3) Storage level constraint:** guarantees that the stored hydrogen at the end of each season does not exceed installed capacity.
- **(C4) Maximum storage potential constraint:** bounds the installed seasonal capacity by a technical or geographical maximum value.
- **(C5) Green quota constraint:** enforces a minimum proportion of hydrogen production to come from electrolysis (e.g., 95
- **(C6) Renewable potential constraint:** limits green hydrogen production to the available renewable electricity allocated for hydrogen use.

- **(C7) Import limitation:** caps total hydrogen imports per year, potentially reflecting terminal capacity or political considerations.
- **(C8) CO_2 emissions constraint:** restricts the total emissions from SMR with CCS, based on emission factors and the carbon budget.
- **(C9–C10) Seasonal stock level balance constraints:** ensure dynamic tracking of stored hydrogen from one season to another, maintaining temporal consistency.
- **(C11) Security stock constraint:** imposes a minimum stock level at the end of summer to maintain strategic reserves, which are assumed to remain unused.

3.6 Robust scenario extension

The above formulation assumes a single deterministic demand scenario (the "central" case). However, one of the objectives of this study is to incorporate demand uncertainty into the planning process. We therefore extend the model to a Scenario-based Robust Optimisation (SRO) approach. In the robust model, instead of one demand scenario, we consider a set S of possible scenarios for future hydrogen demand: for example, S = low, central, high. The central scenario corresponds to the reference demand trajectory (25 TWh → 50 TWh as used above). The high scenario could assume, say, +30% higher demand in both 2035 and 2050 (i.e. roughly 32.5 TWh in 2035, 65 TWh in 2050), representing a world with faster economic growth or more aggressive hydrogen adoption (perhaps due to strong policy support or technological breakthroughs leading to new hydrogen uses). Conversely, the low scenario might assume –30% lower demand (17.5 TWh in 2035, 35 TWh in 2050), reflecting slower hydrogen uptake or competition from other solutions (e.g. electrification or alternative fuels) . These ±30% variations are chosen based on ranges found in literature and policy documents, for instance, the CREG (2024) report and statements from the Belgian government SPF Economie (2022) indicate that actual hydrogen demand could reasonably deviate by these magnitudes from the central case. They are also consistent with the scenarios examined by Zhou et al. (2024) in the reference study.

In the robust model, we retain the same decision variables and general constraints, but we must index certain variables by scenario. We treat the capacity decisions (CapProd and CapStore) as here-and-now decisions, these must be chosen before knowing which demand scenario will occur. In other words, there is one CapProd_p,2035 that must serve all scenarios in 2035 and similarly for 2050. By contrast, the operational decisions (like how much to produce, import, store in/out in each season) can be thought of as recourse (adaptive) decisions that can adjust depending on the scenario.

This reflects a "two-stage" decision structure, first stage is building capacities (must be robust against uncertainty), second stage is operating those capacities optimally for each realized scenario. This approach, sometimes called a perfect recourse two-stage robust model, is a compromise between a fully deterministic approach and a fully robust (min-max without recourse) approach. It acknowledges that while we must invest not knowing future demand, we will in reality adjust operations if demand turns out high or low. In formal terms, we index the seasonal operational variables by scenario sc $\in$ S but not the capacity variables (CapProd and CapStore are common to all scenarios). The constraints such as capacity limits, quotas, $\ldots$, generally must hold in each scenario. For instance, the demand balance constraint now reads:

$$\sum_p \text{Prod}_{p,y,s,sc} + \text{Import}_{y,s,sc} + \text{StoreOut}_{y,s,sc} = \text{demand}_{y,s,sc} + \text{StoreIn}_{y,s,sc}, \quad \forall y, s, \forall sc \quad (2)$$

The green quota must hold in each scenario (or specifically for demand of that scenario). Crucially, the production capacity constraint now ties all scenarios because the same CapProd appears in each:

$$\text{Prod}_{p,y,s,sc} \leq \text{CF} \cdot \text{MW\_to\_TWh} \cdot \text{CapProd}_{p,y}, \quad \forall sc \quad (3)$$

This means we choose one capacity that must accommodate production in all scenarios (which effectively will be sized for the highest demand scenario's needs, unless cost trade-offs allow some shortfall in low scenario, but since we enforce meeting demand in each scenario, capacity must be enough for the highest demand case).

The objective function for the robust model is designed to find a capacity plan that minimizes the "worst-case" cost among the scenarios. A strict robust optimization would minimize the maximum cost across scenarios. To linearize this, one often introduces an auxiliary variable Z that is constrained to be $\geq$ total cost in each scenario, and then minimize Z. However, in our implementation we took a simpler approach: we minimize the sum of costs across all scenarios, without assigning probabilities (effectively assuming equal weight) (Zhou et al., 2024). Because each scenario's cost is composed similarly and the high-demand scenario typically incurs the largest cost, minimizing the sum tends to also minimize the maximum. In fact, with symmetric consideration, this approach will yield a solution very close to the true min-max solution, the model will invest just enough to handle the high scenario because that dominates the sum if not addressed. The result is a robust capacity configuration that works well for all three demand scenarios considered.

To summarize, the robust SRO model chooses capacity investments (electrolyzers, SMR and storage) that simultaneously satisfy the constraints for multiple demand scenarios and it does so in a cost-optimal way that hedges against the worst-case demand. The difference from the deterministic model is that we allow extra capacity to be built to ensure feasibility under the high demand scenario, at the expense of possibly being under-utilized in the low demand scenario. The solution thus represents a trade-off: it avoids disaster in a high-demand future (by having sufficient capacity) while keeping the cost increase moderate if demand ends up low (some capacity might be idle but we limit over-investment because of cost minimization). This robust planning approach is inspired by and consistent with the methodology of Zhou et al. (2024), who applied a similar two-stage robust optimization for hydrogen infrastructure planning under demand uncertainty.

4 Application

4.1 Implementation

The described model was implemented in Python using the Pyomo library, an open-source mathematical modelling tool widely used in energy planning. Pyomo allows for declarative definition of variables, parameters, constraints, and the objective function within Python code, and solves the problem using a linear optimisation solver. In this case, we used the CBC (Coin-Or Branch and Cut) solver, an open-source MILP solver, which is appropriate as our problem is continuous linear and of small size.

The code is structured into two main modules: Deterministic.py and SRO.py (see appendix), corresponding respectively to the deterministic model and the robust model. In practice, to avoid duplication, the SRO code encompasses the deterministic case by considering a single central scenario if needed. However, for the sake of clarity, we initially wrote a simplified version dedicated to the deterministic model.

The model data is read from an Excel file (Data - H2.xlsx). This file contains a table listing all the parameter values discussed (costs, demands,. . .). This setup makes it easy to modify a value or test a different demand scenario by simply changing the corresponding cell. The code reads this file and populates a dictionary of parameters. It also performs some unit conversions (e.g., converting costs from €/kg as given in the sources to €/TWh for the model, using the factors mentioned in Section 3.3). This ensures dimensional consistency within the model.

The CBC solver is launched via Pyomo and returns the optimal values of the variables. The code then formats the results for display. We included verification elements in the final output for instance, displaying for each scenario the demand versus the available supply to ensure that the demand satisfaction constraint is indeed binding (which it was). Similarly, the installed capacities and total system cost are printed. The entire optimization code (Pyomo model and data reading) consists of approximately 300 lines, which remains fairly compact. In the appendix, we provide commented excerpts from the source code to clarify how it works. The full listing is also available in the attached files. Using Pyomo ensures that the mathematical model and the code are well aligned, as the equations are directly translated into Python expressions.

4.2 Results of the deterministic model

The deterministic model optimizes the Belgian hydrogen system to meet an annual demand of 25 TWh in 2035 and 50 TWh in 2050, under constraints such as green hydrogen quotas, emission limits, and import capacities. Below is a summary of the key results obtained.

Installed capacities: The deterministic model predominantly relies on domestic green hydrogen production via electrolysis. Installed electrolyser capacity reaches approximately 951 MW in 2035, expanding significantly to around 3.0 GW by 2050. Interestingly, while blue hydrogen (SMR_CCS) is completely excluded in 2050, it appears economically viable in 2035, resulting in an installed capacity of about 473 MW. This reflects the transitional role of blue hydrogen to meet intermediate targets, where green hydrogen quotas permit a limited but significant share of non-renewable hydrogen in 2035.

Seasonal storage role: The optimized storage capacity is moderate, with the model selecting approximately 0.02 TWh of seasonal storage in 2035 and doubling to 0.04 TWh by 2050. This capacity, although smaller than previously estimated, effectively manages minor seasonal imbalances. Hydrogen produced in excess during summer is stored and utilized in winter, aligning with the strategic objective of smoothing seasonal demand fluctuations. However, the relatively small storage capacity indicates that seasonal variations are mostly balanced by import flexibility rather than extensive storage infrastructure.

Hydrogen imports: Imports play a substantial role, particularly in winter. In 2035, the system imports approximately 9.96 TWh (covering around 40% of annual demand), nearly reaching the permitted limit. By 2050, imports decrease proportionally, representing about 12.34 TWh (around 25% of annual demand). The economic advantage of domestic electrolysis, despite its higher initial investment, limits the extent of imports. The selected import levels reflect an optimal balance between cost efficiency and supply security, reducing Belgium's reliance on external hydrogen supplies while leveraging international markets to ensure stability.

Global energy mix in 2050: In the deterministic scenario, Belgium's 2050 hydrogen demand (50 TWh) is primarily met by domestic electrolysis (approximately 47.5 TWh annually, or 95% of the demand), complemented by strategic imports of roughly 2.5 TWh annually. No blue hydrogen is included by this stage, aligning with stringent environmental constraints. Seasonal storage contributes modestly yet crucially by redistributing approximately 0.08 TWh from summer to winter. This optimized mix significantly enhances Belgium's energy independence and environmental objectives, although results remain sensitive to assumptions on renewable energy potential and cost factors.

4.3 Results of the SRO model

The SRO (Stochastic Robust Optimization) model addresses demand uncertainty explicitly by considering three demand scenarios: low, central, and high. The robust solution ensures sufficient infrastructure capacity to handle these scenarios.

Consequently, installed capacities increase compared to the deterministic model. Electrolysis capacity remains at approximately 951 MW in 2035, similar to the deterministic model but storage and SMR_CCS play a more noticeable role. Blue hydrogen capacity is approximately 473 MW in 2035, offering flexibility to manage uncertainty. By 2050, the robust model confirms the deterministic model's decision to exclude blue hydrogen, maintaining electrolysis capacity at roughly 3.0 GW.

Storage capacity in the robust scenario is consistent with the deterministic model, at about 0.02 TWh in 2035 and 0.04 TWh in 2050. These figures suggest limited but strategic seasonal storage, adequate to address variations in demand between summer and winter without unnecessary capital expenditure.

The total system cost under the central robust scenario increases moderately to approximately €10.65 billion. This 21% increase over the deterministic model stems primarily from the inclusion of SMR_CCS and a slightly greater dependence on imported hydrogen, necessary to handle higher potential winter demands under uncertainty. In the central scenario, imports account for about 40% of annual demand in 2035 (around 10 TWh) and approximately 35% in 2050 (around 17.42 TWh), emphasizing the strategic role of imports as a flexible supply buffer.

The robust model's value becomes apparent in the high-demand scenario, effectively meeting elevated demand through strategically planned infrastructure without further costly adaptations. Conversely, in the low-demand scenario, the moderate oversizing of capacity represents an acceptable trade-off for energy security and flexibility.

Overall, this analysis highlights two approaches: a deterministic optimization focusing on cost-minimal solutions under fixed assumptions, and a robust optimization prioritizing resilience against demand fluctuations. The robust solution aligns well with the Belgian strategic vision, favoring a moderate infrastructure overcapacity that safeguards against future uncertainties while maintaining environmental objectives and minimizing excessive reliance on imports (Laurent Remy, 2025).

4.4 Sensitivity analysis

To assess the robustness of our results and identify the main determinants influencing the optimized hydrogen system, we carried out a sensitivity analysis on three key parameters: the green hydrogen quota, the import limit, and renewable energy potential. The detailed results of these analyses, illustrated by specific graphs, are provided in Annex A.

4.4.1 Sensitivity to the green quota

The green hydrogen quota, representing the mandatory share of renewable hydrogen in total consumption, strongly influences system costs and the technology mix .1(Annex A, Figures A.1 and A.2). Increasing this quota from 50% to 100% in 2050 significantly raises the total system cost from €10.63 billion to approximately €10.66 billion. This increase, although moderate in absolute terms, highlights the economic premium associated with higher environmental ambitions.

In terms of installed capacity, lower quotas (around 50-60%) favor maintaining significant blue hydrogen production capacities (SMR_CCS), approximately 900 MW. However, once the quota surpasses 70%, the model gradually phases out SMR_CCS, replacing it with electrolyser capacity, reaching approximately 3 GW at a 100% quota. This shift underscores the competitiveness of electrolysis as environmental constraints tighten.

4.4.2 Sensitivity to the import limit

Varying the hydrogen import limit between 10 and 30 TWh/year in 2050 significantly impacts the total system cost and installed capacities (Annex A, Figures A.3 and A.4). With restrictive import limits (10 TWh/year), the total system cost sharply rises to about €10.83 billion due to increased reliance on more expensive domestic solutions. Conversely, as import capacity grows, costs decrease and stabilize at around €10.65 billion from 17.5 TWh/year onward, indicating the system reaches an economic optimum above this threshold.

The impact on installed capacities is also noticeable. Lower import limits necessitate maintaining some blue hydrogen production (about 500 MW SMR_CCS capacity at 10 TWh import limit). As import limits rise, reliance on SMR_CCS diminishes, eventually being completely replaced by electrolysis beyond 17.5 TWh/year, stabilizing electrolyser capacity at around 3 GW. This highlights the strategic importance of flexible import capacity to optimize costs and minimize fossil-based hydrogen production.

4.4.3 Sensitivity to renewable potential

Renewable energy potential critically determines system feasibility and capacity choices (Annex A, Figures A.5 and A.6). Below a renewable potential of 40 TWh/year, the model becomes infeasible, unable to satisfy the high green hydrogen quotas (95% for 2050). This clearly demonstrates that meeting ambitious renewable hydrogen targets requires a minimal renewable energy threshold.

Above this critical threshold, increasing renewable potential from 40 TWh/year to higher values provides marginal economic benefit, as costs remain relatively stable around €10.65 billion. Installed capacities stabilize accordingly, dominated by electrolysis (approximately 3 GW), with SMR_CCS becoming redundant. Thus, the renewable energy availability acts primarily as an enabling factor rather than a cost-reducing lever.

4.4.4 Synthesis of the sensitivity analysis

Overall, the sensitivity analysis underscores the central role of environmental constraints (green hydrogen quotas) and renewable resource availability. These two parameters fundamentally dictate both system feasibility and the optimal technological mix. While import capacity notably influences system costs and installed capacities, it primarily serves as a flexibility mechanism. Policymakers must thus carefully balance ambitious green hydrogen objectives with sufficient renewable resource development and flexible import infrastructures to ensure both economic efficiency and environmental sustainability.

5 Conclusion

5.1 Summary

This study proposes an optimized development plan for the hydrogen system in Belgium over the 2035–2050 horizon, combining techno-economic modelling with scenario-based and robust optimization approaches. The central result highlights the predominant role of green hydrogen produced through electrolysis, powered by a maximum deployment of national renewable resources. By 2050, the model recommends installing approximately 3 GW of electrolysers, supported mainly by offshore wind, covering about two-thirds of the forecasted hydrogen demand (around 50 TWh). The remaining demand would be met through imports of green hydrogen, while the use of blue hydrogen (SMR_CCS) is limited or absent depending on environmental constraints.

Strategic hydrogen storage emerges as a critical enabler of seasonal flexibility. The model identifies the need for about 0.04 TWh of storage capacity by 2050, facilitating the shift of surplus summer production to winter, where demand peaks. Although relatively modest compared to earlier projections, this storage plays a stabilizing role in balancing the system across seasons and safeguarding security of supply.

Incorporating demand uncertainty via the robust optimization framework provides additional insights into infrastructure planning. Under adverse scenarios with increased demand, the model anticipates preventive investments in both electrolyser and storage capacity. While this leads to higher costs, the impact remains limited in relative terms (under 10%), demonstrating the cost-effectiveness of building resilience into the system.

The sensitivity analysis reinforces the central importance of environmental and structural parameters. The green quota, the national renewable potential and import constraints significantly influence the system's configuration and economics. In particular, relaxing the green quota or increasing the renewable resource base can reduce costs substantially, whereas strict environmental targets require greater reliance on domestic production. Conversely, variables such as SMR_CCS investment cost or hydrogen import price have marginal influence under current assumptions. These findings confirm that long-term policy goals and infrastructure availability are the main levers shaping Belgium's hydrogen future.

5.2 Limits

While the model provides clear and operational insights, several limitations must be acknowledged. The temporal resolution used in this study (two seasons and two representative years) does not fully capture intra-annual or inter-annual variations. A more refined temporal structure could improve the accuracy of system operation and investment phasing.

The scenario relies on long-term techno-economic projections that remain uncertain. Future costs of electrolysers, hydrogen imports, storage technologies, and carbon pricing are subject to change and could alter the optimal configuration. Moreover, the real technical feasibility of large-scale hydrogen storage, especially in geological formations, requires further validation.

The analysis focuses on a high-level national view and does not capture the spatial distribution of infrastructure, internal transport needs, or grid integration challenges. Additionally, the model abstracts from external risks such as extreme weather events or geopolitical disruptions that could impact supply chains or system reliability.

Finally, Belgium is treated as an isolated system without considering the dynamic interactions with neighboring countries. Yet, given its central role in European energy networks, a cross-border perspective would allow the identification of regional synergies and improve the realism of long-term infrastructure planning.

5.3 Future directions

Several avenues could be explored to strengthen and extend this work. Increasing the temporal granularity and adding intermediate years would enable finer tracking of system evolution and seasonal dynamics. Incorporating sectoral demand breakdowns and end-use profiles could also help tailor supply strategies to specific consumption patterns.

At the spatial level, modelling the hydrogen transport network and its interaction with electricity grids would help identify possible bottlenecks and synergies, especially for offshore infrastructure. Integrating Belgium within a broader European framework would also allow a joint optimization of production, storage and imports, revealing cooperation opportunities at regional scale.

Finally, the robust approach could be expanded to include multiple uncertainties simultaneously,such as renewable variability, technology costs, or policy targets, to assess the full spectrum of risk and develop a more resilient investment strategy.

In conclusion, this thesis presents a solid foundation for a coherent, cost-effective, and environmentally sustainable hydrogen strategy in Belgium. The results call for long-term coordination between public authorities, infrastructure operators, and industrial players to ensure a timely and robust deployment of the national hydrogen system.

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Appendix A: Sensitivity analysis graphs

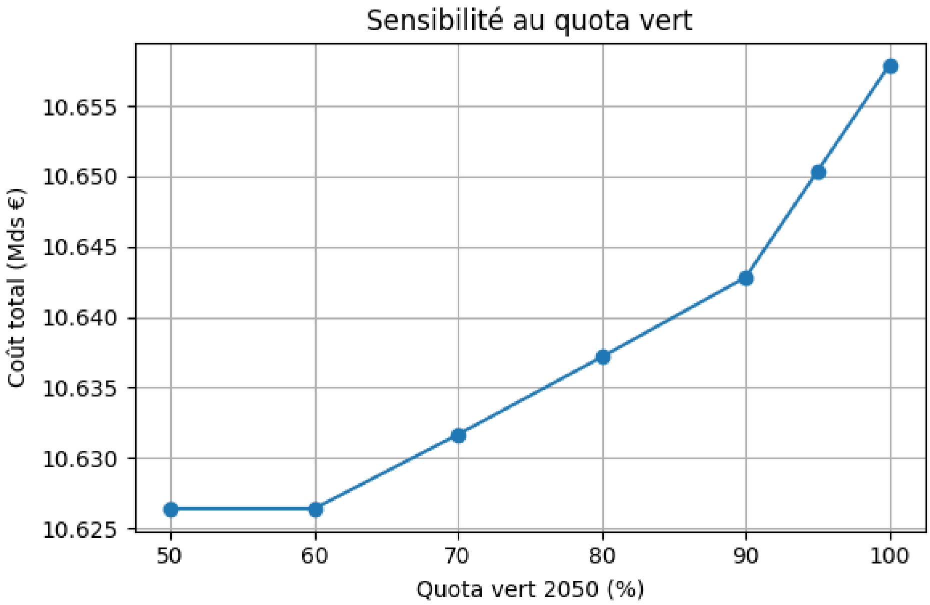

Figure .1: Sensitivity to green quota

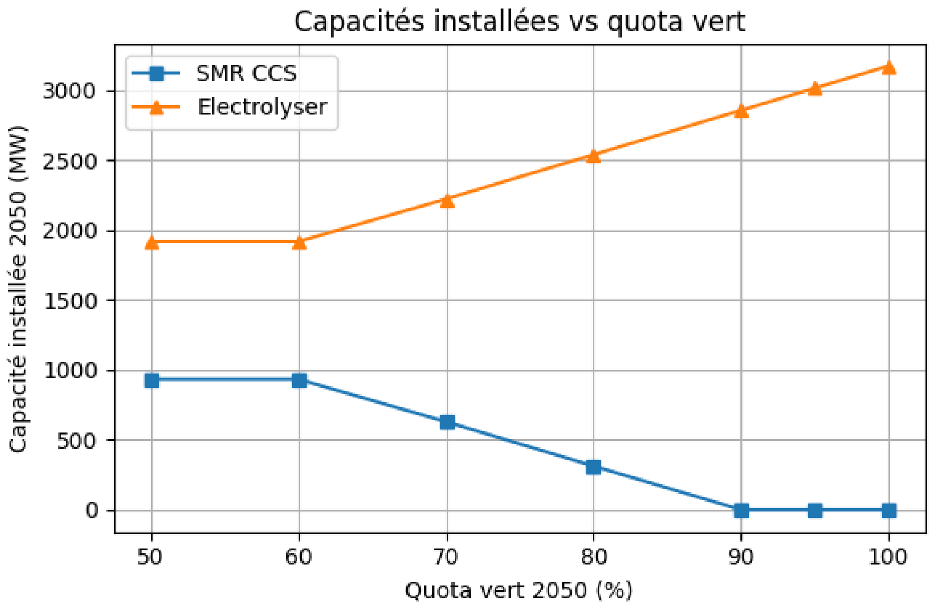

Figure .2: Installed capacity vs green quota

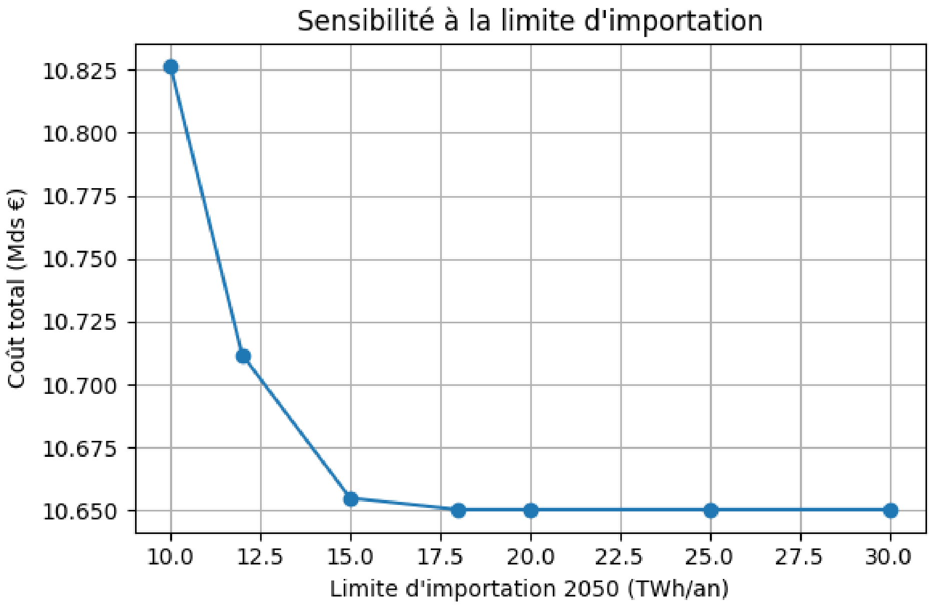

Figure .3: Sensitivity to import limits

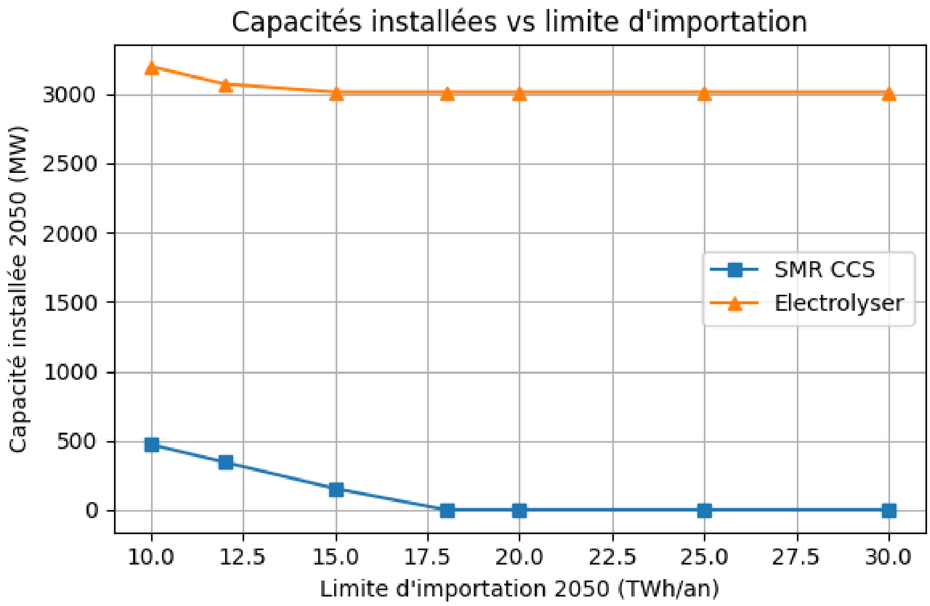

Figure .4: Installed capacity vs import limit

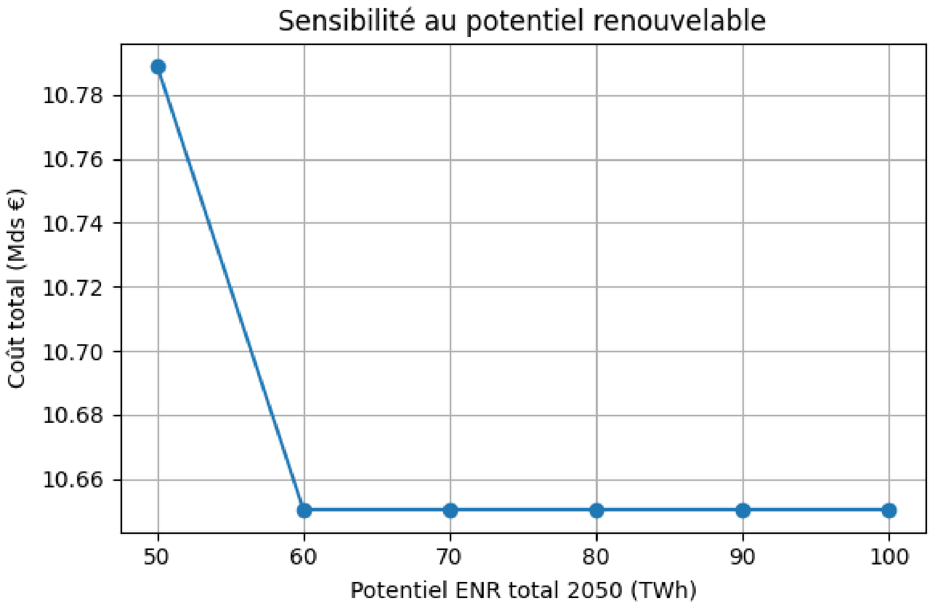

Figure .5: Sensitivity to renewable potential

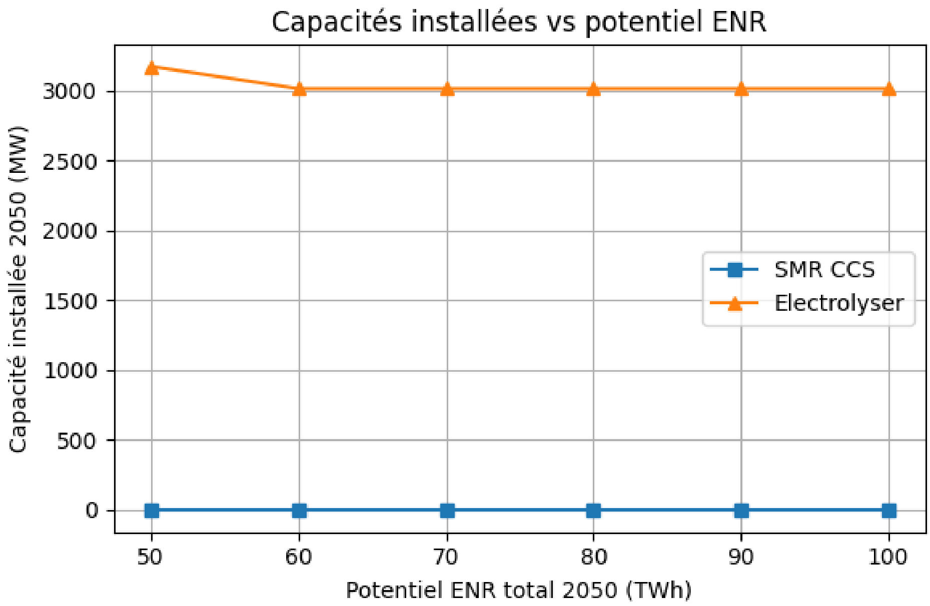

Figure .6: Installed capacity vs renewable energy potential

Appendix B: Interview with Rémy Laurent (In French)

Interview de Rémy Laurent (External Relations Manager chez Fluxys et auparavant membre de NextGrid, la section hydrogène de Fluxys). Interview réalisée en Français le 15 mai 2025 par Augustin Dekegel dans le cadre du mémoire de fin de master d'ingénieur de gestion à la LSM.

AD : Augustin Dekegel
RL : Rémy Laurent

AD : Bonjour monsieur, vous allez bien ?

RL: Bonjour Augustin.

RL : Oui, très bien merci

AD : Donc voilà, est-ce que ça vous dérange que j'enregistre la réunion pour l'intégrer ensuite à mon travail ?

RL : Non, non, pas du tout. Alors, je vais faire ça tout de suite.

AD : Voilà, c'est bon. Donc, je vais commencer tout de suite, on ne va pas perdre de temps. Déjà, je vous remercie d'avoir accepté cette réunion pour répondre à mes quelques questions à propos de mon mémoire, ça va beaucoup m'aider.

AD : Comme je vous l'avais déjà dit, je suis étudiant en master 2 à l'UCLouvain, dans un master d'ingénieur de gestion avec une spécialisation en supply chain. Et donc, la problématique de mon mémoire d'études traite de comment la Belgique peut-elle développer un réseau de distribution d'hydrogène efficace et robuste, malgré les incertitudes de marché et les contraintes d'importation.

AD : C'est donc tout logiquement que l'entreprise Fluxis m'intéressait parce que vous êtes très actif dans le domaine de l'hydrogène et cela fait que j'ai quelques questions à vous poser. Est-ce que vous pouvez commencer par vous présenter rapidement et quel est votre rôle au sein de Fluxis ?

RL : Oui, tout à fait. Donc voilà, je m'appelle Laurent Remy, je suis External Relations Manager, ça veut dire que je suis actif au sein du département communication externe de chez Fluxis. J'ai passé deux ans dans la business unit NextGrid. Avant ça, donc NextGrid, c'est une business unit qu'on avait créée au sein de Fluxis pour examiner les possibilités de développement en termes d'hydrogène et de CO2. Donc il faut savoir que Fluxis a la volonté de diversifier quelques peu ses activités.

RL : Donc on veut transformer notre réseau qui aujourd'hui transporte presque exclusivement du gaz naturel vers un réseau qu'on appelle multimolécules où à côté du gaz naturel, on va transporter de l'hydrogène d'une part, mais aussi du CO2. Donc l'idée au niveau de l'hydrogène, c'est d'en importer par le biais des ports, d'en produire aussi localement, bien sûr, dans la zone où c'est possible, de transporter vers les gros clusters industriels belges, mais aussi vers les clusters industriels situés à l'étranger. Donc on va un peu, quelque part, pérenniser notre position en tant qu'acteur de transit.

RL : Et pour le CO2, là, on part dans un flux différent. Donc l'idée, c'est de faire capturer le CO2 par les entreprises émettrices de CO2, de l'injecter dans un réseau de transport de CO2 où viendraient s'ajouter des quantités de transit en provenance, par exemple, de l'Allemagne, des zones fortement industrialisées de l'Allemagne. Donc d'y ajouter les émissions des joueurs belges et puis d'aller vers les ports.

RL :Ils représentent des solutions d'exportation de CO2. Donc l'idée étant de le séquestrer dans des structures géologiques appropriées. Voilà, ça c'est un petit peu en deux mots.

AD : Ok, merci. Donc ici, on va principalement se concentrer sur l'hydrogène.

AD : Et donc, vous l'avez déjà un peu expliqué, mais le rôle de fluxys au sein du marché de l'hydrogène, principalement en Belgique, et du coup, le transport, le stockage, de ce que j'ai compris, en partie. Et est-ce que Fluxus s'occupe aussi de la distribution directement vers les clusters industriels ? Par exemple si la demande devient plus particulière, un peu comme les gaz naturels, est-ce que Fluxus a pour vocation de s'occuper de la distribution aussi ou plutôt de la déléguer à d'autres entreprises, comme il y a Sybelga ou Ores pour le gaz ?

RL : Alors, on pense qu'on est parti plutôt vers un modèle basé sur le modèle du gaz naturel, c'est-à-dire que Fluxys va se limiter aux activités de transport. Donc nous, notre rôle aujourd'hui pour le gaz naturel, c'est ça en fait, c'est d'effectuer le transport du gaz à haute pression depuis les points d'entrée du réseau. Donc, on a un réseau qui est super bien interconnecté avec 18 points d'interconnexion au total avec les pays adjacents. Donc, c'est de transporter le gaz depuis ces points d'interconnexion vers des clients finaux.

RL : Alors, les clients finaux au jour d'aujourd'hui, c'est qui ? Ce sont les gros clients industriels type ArcelorMittal, BASF, IARA, enfin voilà, vraiment des gros clients comme ça, des centrales électriques et les réseaux des gestionnaires de réseau de distribution. Donc, ça veut dire que nous, on s'arrête à un certain niveau de pression. Typiquement, ça va être 15 bars et on a des points d'interface qui sont définis, on appelle ça dans nos jargons des city gates. Les Français appellent ça des points d'interface transport distribution où, à ce moment-là, on transfère le gaz naturel vers les gestionnaires, les GRD, les gestionnaires de réseau de distribution, que ce soit en Wallonie, Resa et ORES, Sibelga, Bruxelles, Fluvius en Flandre. Et eux assurent à ce moment-là la distribution du gaz vers typiquement les particuliers d'une part et les petites et moyennes entreprises d'autre part. Donc, ça, c'est plus ou moins le modèle qui va être répliqué au niveau de l'hydrogène.

RL : Peut-être une petite exception près, c'est que pour le moment, on ne voit pas pour l'hydrogène à être débouché au niveau de la distribution. Donc, l'hydrogène, je pense, a vocation à remplacer le gaz naturel auprès des gros clients industriels. Donc, ça, c'est un petit peu le message que l'on a capté quand on les a approchés pour définir un peu comment notre futur réseau pourrait être dimensionné.

RL : Je pense qu'au niveau énergie et les particuliers, je pense que toutes les régions poussent fortement vers une électrification et autrement d'hiver, une utilisation accrue des

pompes à chaleur. Et donc, l'hydrogène n'a pas vocation à être à destination résidentielle, de chauffage résidentiel ou à des voitures particulières.
AD : Techniquement, ce serait faisable ?

RL : Oui, c'est le même. Donc, ça a été testé, notamment en Angleterre. Il y a un projet qui est assez intéressant qui s'appelle Future Grid. Si tu tapes ça sur Google, tu vas trouver assez facilement des informations qui est poussé par notre pendant anglais qui s'appelle National Gas. Et voilà, eux, ils ont réussi à reconstruire, si tu veux, un réseau à partir de parties de réseaux qui avaient été mis hors service. Donc, ils ont testé des compresseurs, des vannes, des tuyaux, des petits stockages. Mais aussi, ils ont livré aussi de l'hydrogène à des maisons. Donc, il y a des chaudières qui existent pour brûler du gaz, pour brûler de l'hydrogène. Donc, voilà, la technique, elle est là, même si l'hydrogène, en fait, c'est un gaz de test.

RL : Donc, au jour d'aujourd'hui, en Belgique, on utilise un mélange de gaz naturel et d'hydrogène pour tester, en fait, notamment la surchauffe dans les chaudières. Donc, au jour d'aujourd'hui, ça veut dire qu'on ne peut pas utiliser 100% d'hydrogène dans les chaudières qui sont installées en Belgique. Mais bon, ça veut dire qu'il faut remplacer quelque part plus de 3 millions de chaudières existantes, ce qui représenterait un certain budget, évidemment.

AD : Et donc, ce n'est pas la priorité qui est choisie par la Belgique actuellement ?

RL : Non, la Belgique, pour le moment, pousse assez fort pour alimenter les gros clients industriels. Alors, l'avantage des gros clients industriels, la majorité connaissent déjà l'hydrogène. Par exemple, je citais tout à l'heure un client comme BASF. BASF, qu'est-ce qu'il fait ? Il prend le gaz naturel qui lui est livré. Donc, le constituant principal du gaz naturel, c'est le méthane, CH4. Il fait le cracking de cette molécule pour obtenir de l'hydrogène. Et avec cet hydrogène, essentiellement, il va produire de l'ammoniaque. Donc, 55% du marché mondial, plus ou moins, de l'hydrogène, c'est orienté par la production de l'ammoniaque. Ammoniaque qui est notamment à la base de tous les engrais. Donc, voilà. Ça veut dire qu'une société comme BASF, si on lui dit, écoutez, demain, on ne vous livre plus du gaz naturel, on vous lit de l'hydrogène à la place. Ça les arrange.

AD : D'accord. Et donc, pour l'instant, les entreprises de distribution comme Ores ne sont pas du tout intéressées pour rentrer sur le marché de l'hydrogène ?

RL : Ce n'est clairement pas la priorité. Non.

AD : Parce que j'ai cherché un peu s'ils étaient sur certains projets ou quoi. J'ai trouvé très peu d'informations. C'est la déduction que j'en ai faites. Je cherche aussi à avoir un contact chez eux pour avoir la confirmation. Mais pour l'instant, je n'ai pas encore eu de réponse.

RL : Non, non. L'hydrogène, clairement, je dirais, le public cible, comme on dirait en communication, c'est plutôt vraiment l'industrie.

AD : Et des informations que j'ai déjà pu récolter de la littérature que j'ai lue, j'ai cru comprendre que le marché de l'hydrogène est assez incertain quant à la demande. Et

donc, j'aimerais savoir comment Fluxys planifie plusieurs années à l'avance sur le long terme la demande pour développer des infrastructures.

Parce que ce sont des investissements sur le long terme. Et donc, comment avoir confiance quand la demande est comme ça incertaine ?

RL : C'est-à-dire qu'il n'y a pas que la demande qui est incertaine. On est un peu dans une situation pour le moment où les producteurs comptent sur la demande pour se développer et les industriels comptent sur les producteurs pour produire. Donc, voilà, c'est un peu l'inconvénient, je dirais, d'un marché naissant, qui est le cas pour l'hydrogène, en tout cas dans un environnement, comme je dirais la Commission européenne le souhaite, c'est-à-dire un environnement dit en open access. Tu dois savoir qu'aujourd'hui, Air Liquide exploite déjà un réseau dans le Benelux. Donc, il y a déjà plus ou moins, en Belgique, 600 kilomètres de canalisation d'hydrogène. Mais on est là dans un environnement de marché où Air Liquide a toutes les casquettes. Donc, il est en même temps producteur, transporteur, vendeur et distributeur. Ça, ce n'est pas évidemment le modèle souhaité par la Commission européenne.

RL : Donc, nous, ce qu'on va faire, c'est développer un réseau beaucoup plus gros. Donc, Air Liquide, il a des canalisations maximum de 100 millimètres ou 20 centimètres de diamètre. Nous, on va aller vers du 500, 600, voire même plus. Donc, on a des ambitions de transporter des quantités qui représentent environ deux fois ce que Air Liquide transporte aujourd'hui. Et Air Liquide, tu dois savoir aussi qu'ils n'ont plus le droit de développer leur réseau. C'est-à-dire que si jamais ils se sont confrontés à une augmentation de la demande qui nécessite des investissements de leur réseau existant, ils doivent d'abord faire appel à nous. Donc, il y a certaines contraintes qui ont été mises à ce niveau-là. Donc, ça, c'est la législation belge qui l'a obligé. C'est la législation belge qui dérive elle-même des différents paquets législatifs européens.

RL : Donc, il y a un dernier package qui avait été pris, je pense qu'il date de juillet 2024. Donc, il est assez récent, qui s'appelle le « Gas Decarbonisation Package », qui dit qu'il faut fonctionner selon certaines règles. Et ces règles, c'est quoi? C'est de l'accès des réseaux routiers, third-party access, ça s'appelle, avec un accès non discriminatoire aux réseaux, avec un régulateur, avec un système tarifaire, etc. Et qui ne fonctionne absolument pas, seulement ce modèle-là, puisqu'il est actif dans, quelque part, tous les éléments de la chaîne de valeur. Ce qui n'est absolument pas le modèle rêvé de la Commission européenne. Alors maintenant, effectivement, des incertitudes, il y en a, puisque avec des sociétés comme nous, on a un business model assez particulier, puisqu'on a des revenus qui sont régulés.

RL : C'est-à-dire qu'on est soumis, bien entendu, à l'approbation du régulateur, qui est la CREG en belgique, la Commission de Régulation de l'électricité et du gaz. Donc la CREG a été nommée officiellement comme régulateur pour l'hydrogène aussi, puisque l'hydrogène a une banque d'énergie, c'est assez logique, à côté de l'électrique et du gaz qui prennent ça en plus. Mais alors, effectivement, on doit discuter avec eux des tarifs. Alors comment est-ce que nous, typiquement, on détermine un tarif ? On regarde quelle est la valeur de notre infrastructure, c'est ce qu'on appelle la RAB, c'est ce qu'on appelle le Regulated Asset Base. Et cette valeur de l'infrastructure, on va quelque part l'amortir sur un certain nombre d'années et on va faire intervenir ce montant dans la détermination des tarifs. C'est-à-dire qu'en gros, les tarifs sont censés couvrir nos coûts.

RL : Alors dans un business naissant, ça veut dire effectivement qu'on va poser des canalisations pour plusieurs centaines de millions d'euros, mais avec peut-être un ou deux clients au début. Alors si on applique la méthodologie tarifaire classique, ça veut dire que ces deux clients vont être fortement pénalisés au début de l'activité, puisqu'ils vont devoir payer des tarifs astronomiques, finalement, pour que nous, on puisse rentrer dans nos frais. Donc ça, ce n'est absolument pas le but. Et donc, c'est pour ça qu'on est en discussion avec les clients, mais aussi avec le régulateur pour mettre un système d'allocation des coûts un peu différent. C'est ce qu'on appelle en anglais le Inter-Temporal Allocation. Donc ça veut dire, ça reconnaît justement ce fait qu'au début, il va y avoir un nombre limité de clients qui vont utiliser seulement une portion de la capacité qu'on va mettre à disposition. Et donc, on va fonctionner avec un espèce de compte d'amortissement, si tu veux, où on est censé avoir un tarif de X pour rentrer dans nos frais. On applique un tarif de X divisé par 3 au début. Ça veut dire que les deux tiers vont quelque part être financés par le biais de subsides, par exemple. Subsides qui pourront être fournis par exemple par l'État. Et alors, au fur et à mesure que le business va se développer, à un moment donné, ce compte de régularisation va atteindre, on va dire, un point minimum et puis il va commencer à remonter vers zéro. Et à ce moment-là, on va commencer à rembourser quelque part ce compte d'amortisation.

RL : Donc, il y a différents mécanismes qui sont d'application. C'est notamment ce qu'ils ont fait en Allemagne, par exemple.

AD : Donc ça, c'est des mécanismes qui régulent un peu les prix et aussi qui diminuent les risques pour Fluxis, j'imagine, les risques financiers ?

RL : Oui, c'est-à-dire que nous, effectivement, on investit sur une canalisation typiquement. Ça a une durée de vie, en termes régulateurs, de 50 ans. Donc nous, quand on va investir dans… Bon, c'est quand même des travaux de grande ampleur. Donc nous, on ne va pas investir dans une canalisation de 200 millimètres de diamètre en sachant que dans 10 ans, on a besoin du double, du triple. Donc on va investir en une seule fois. On va mettre ces canalisations dans le sol, avec dans l'idée vraiment que dans 10, 20, 30 ans, le marché sera à tel ou tel endroit. Parce que sinon, effectivement, on en arriverait un peu comme dans certaines situations un peu malheureuses où Belgacom vient un jour creuser dans ton trottoir, il rebouche. Et puis le lendemain, il y a Electrabel qui vient. Et puis le lendemain, il y a la société wallonne des eaux qui vient. Voilà, c'est embêtant pour tout le monde. Donc nous, généralement, effectivement, on fait ça une fois. Donc on ouvre le sol, on pose une grosse canalisation dedans, on referme, on ne nous voit plus. Et voilà, on est opérationnel pour le très long terme.

RL : Maintenant, ça nous arrive aussi. On a eu l'occasion ces dernières années où il faut renforcer le réseau parce qu'un nouveau client industriel d'importance s'installe. Alors à ce moment-là, si on n'a pas suffisamment de capacité, on peut être amené effectivement à renforcer notre réseau. Ça, c'est certain. Mais quand on pose une nouvelle canalisation, comme ça sera le cas ici pour l'hydrogène, comme on dit toujours, elle est future proof, c'est-à-dire qu'elle est construite pour faire face à la demande au niveau du long terme.

Alors maintenant, ce qu'on a fait ici, tu l'as peut-être vu dans la presse, mais on a décidé d'investir dans une première partie de notre backbone hydrogène.

Et donc, on a la volonté d'être opérationnel en 2026 avec une première canalisation qui se trouve entre les clusters industriels de Gand et d’Anvers. Petit souci pour le moment, c'est que le permis a été attaqué en fait par des agriculteurs parce qu'ils craignent qu'il y ait un risque au niveau de l'eau qu'ils utilisent pour leur culture. Et donc, pour le moment, ce permis a été suspendu. Mais voilà, on est en discussion avec eux et on a bon espoir qu'on puisse recommencer les travaux assez rapidement. Mais donc, l'idée qu'on a eue, c'est que même si on n'a pas encore de contrats fermes qui sont signés par des industries chez nous, ou par des clients pour réserver de la capacité dans les futures installations, on a dit voilà, nous, on est assez volontariste, on ne veut pas que notre réseau, que le manque de développement de réseau soit dans le chemin des utilisateurs une fois qu'ils veulent l'utiliser. On ne peut pas se permettre de dire, écoutez, on attend que la production soit prête, on attend que la demande soit prête. Le jour où ces deux-là sont prêts, ils viennent chez nous, ils nous disent, voilà, monsieur Fluxys, nous souhaiterions maintenant utiliser un réseau. Entre le moment où on organise les premières sessions d'information pour le développement d'un réseau et le moment où le réseau est effectivement dans le sous-sol et opérationnel, tout a quand même compté 3 à 4 ans. Donc, à ce moment-là, on s'est dit, voilà, comme on sent que le business est là, il ne manque pas grand-chose pour que le marché de l'hydrogène se lance, nous, on va déjà prendre les premiers pas et mettre déjà une partie du réseau à disposition.

AD : Donc, de cette façon, vous avez une assez bonne confiance en la demande future pour développer votre capacité de transport ?

Oui, je pense que c'est, comme disent les Anglais, it's a no-brainer. L'hydrogène n'est pas la seconde du jour, ce n'est pas la solution miracle. Il n'y a pas de solution miracle pour réussir la transition énergétique, mais l'hydrogène est très certainement un des outils qui va être nécessaire à aider cette transition énergétique, non seulement en Belgique, mais dans les pays adjacents. Donc là, clairement, l'Allemagne est un très gros marché de l'hydrogène au jour d'aujourd'hui. L'Allemagne a l'ambition de doubler ses prélèvements d'hydrogène d'ici 2030. Donc, l'Allemagne est très volontariste et on est très bien situé en Belgique. Pour leur fournir des quantités d'hydrogène.

AD : y’a-t-il des incertitudes en ce qui concerne le cadre régulatoire en Belgique ?

RL : En Belgique, il n'y a pas d'incertitude, à proprement parler, pour tout ce qui est le cadre régulatoire. Donc nous, la Belgique est l'un des premiers pays au monde à avoir une stratégie d'hydrogène. La Belgique a une loi hydrogène. Depuis l'année passée, Fluxys a été officiellement désigné Hydrogen Network Operator par la ministre, certifié par la CREG. Donc voilà, en Belgique, je dirais, le cadre régulatoire est très clair. Maintenant, le problème se situe plutôt, je dirais, au niveau de la molécule. Où il y a une incertitude au niveau de la production et au niveau de la demande.

RL : Puisque la commission européenne pousse très fort pour utiliser ce qu'on appelle de l'hydrogène vert. C'est ce qu'ils appellent dans leur nomenclature, je dirais, Renewable Fuel of Non-Biological Origin, RFNBO. Le souci, c'est que cet hydrogène vert, il est assez coûteux pour le moment.

Et assez peu produit aussi, actuellement. Plus de 95% de l'hydrogène produit au niveau mondial est l'hydrogène qu'on appelle l'hydrogène gris. C'est-à-dire qu'il est produit à partir, justement, du SMR, donc Steam Methane Reforming, donc le craquage ou le vaporeformage du méthane. Qui est un hydrogène vraiment polluant, puisque hors de grandeur, par tonne d'hydrogène qu'on produit, on libère 9 à 11 tonnes de CO2. Donc ça, évidemment, la commission ne pousse pas vers cet hydrogène gris. Elle, elle veut vraiment l'hydrogène vert produit à partir de l'électrolyse de l'eau, même si les besoins d'électricité sont absolument astronomiques.

RL : Et donc, nous, on pense, mais on n'est pas le seul à le penser, qu'il faut passer, en fait, dans une phase intermédiaire par ce qu'on appelle l'hydrogène bleu. Et donc, l'hydrogène bleu, c'est quoi ? C'est l'hydrogène gris, mais avec le captage et le stockage du CO2 qui est émis. Il faut savoir que si tu utilises... À ce moment-là, tu vas utiliser un autre process, ça ne sera plus du steam methane reforming, mais ça sera du auto-thermal reforming, un ATR, ça s'appelle. L'avantage de l'ATR, c'est que ça te donne des... Bon, il faut monter plus en température, mais d'un autre côté, ça te donne des flux de CO2 beaucoup plus concentrés. Et donc, ça te permet d'atteindre une captation jusqu'à 95% du CO2 émis. Et donc, là, on se trouve vraiment dans une configuration qu'on appelle Low Carbon Hydrogen, selon la nomenclature européenne. On l'appelle l'hydrogène bleu, puisqu'on travaille beaucoup avec les couleurs dans le cadre de l'hydrogène. Mais ça, on pense que ça peut vraiment aider à développer le marché. Donc, pareil, pour un peu fixer les idées, il y a un projet dans l'arrière-cour de Zébruges qui est un projet porté par Veria, qui est une filiale du groupe Colruyt. Celle-là, c'est du Belgobelge. Et Veria est en train de développer un électrolyseur dans le cadre d'un projet High Of Wind. On parle de 25 mégawatts électriques. 25 mégawatts électriques, ça va te donner plus ou moins 3 500 à 4 000 tonnes d'hydrogène pour un marché aujourd'hui de 400 000 tonnes en Belgique. Donc, c'est minime. Donc, c'est vraiment minime.

RL : Par contre, d'un autre côté, tu as deux acteurs d'importance qui sont Engie, d'un côté, et Equinor, de l'autre. Alors, Equinor, c'est un très gros producteur norvégien de gaz notamment, mais pas que. Et eux, ils ont la volonté de construire en fait un site dans la région de Gand. C'est le projet qui s'appelle H2B. Donc, ça s'écrit H-2-B-E. Et ce projet H2B, c'est un projet de 1 gigawatt. Et avec ce projet de 1 gigawatt, ils ont l'ambition de pouvoir produire 200 000 tonnes d'hydrogène bleu. Donc, ça veut dire qu'avec un seul projet comme ça, ils couvriraient la moitié de la demande actuelle belge d'hydrogène. Donc là, on est parti évidemment sur des ordres de grandeur tout à fait différents.

RL : En plus, avec une belle synergie, et c'est là qu'il faut faire le lien évidemment avec le développement de notre réseau de CO2, c'est qu'ils prendraient du gaz en provenance de Norvège. Ils feraient à ce moment-là, via la TR, ils craqueraient le méthane en hydrogène avec production de CO2. Ce CO2 serait capté et renvoyé par une nouvelle canalisation sous-marine vers une structure géologique en Norvège. Et donc là, on est vraiment dans un système beaucoup plus vertueux de production d'hydrogène que d'utilisation d'hydrogène irrigue.

AD : Ok, je comprends. Et donc, quand vous avez planifié cette demande, quand vous avez compris quelle sera la demande dans le futur, comment vous décidez de quelle façon vous développez le réseau géographiquement ? C'est pour aller vers les hubs industriels j'imagine ? Mais aussi, comment vous prenez la décision de transformer des anciennes canalisations de gaz naturel en hydrogène, ou alors de carrément créer de nouvelles canalisations, un nouveau réseau ?

RL : Alors, il faut savoir à terme, comment on arrive au développement du réseau c'est essentiellement par des contacts avec les industriels. Donc, on a toute une équipe commerciale qui a un portefeuille de clients. Et donc là, c'est en allant les voir, en discutant avec eux, mais tiens, quels sont vos besoins, ça sera plus ou moins à quel moment, etc. C'est un peu sur base de leur feedback qu'on va développer le réseau. Ça c'est très clair. Maintenant, effectivement, on est en plein dans une étude avec l'Université de Gand. On leur a demandé de faire un peu le mapping de notre réseau existant de gaz naturel. Aujourd'hui, on exploite en Belgique environ 4000 kilomètres de canalisation et de pression. On leur a demandé à l'Université de Gand de cartographier ce réseau, tronçon par tronçon, presque soudure par soudure, pour voir si notre réseau peut être réutilisé pour transporter de l'hydrogène.

RL : Et donc là, c'est un peu la bonne nouvelle, c'est qu'on pense que plus de 80% de notre réseau peut être réutilisé pour le transport d'hydrogène, même s'il y a quand même des points d'attention. C'est-à-dire que quand on fait ce qu'on appelle du repurposing ou du retrofitting, c'est le même mot, quand on réutilise un réseau existant qui a transporté du gaz naturel, il faut faire un peu attention à la qualité de l'acier et à la façon dont cet hydrogène va interagir avec l'acier. Donc l'hydrogène, c'est vraiment une molécule qui est super petite, beaucoup plus petite que le gaz naturel, et donc qui peut avoir tendance à aller s'insérer dans des infructuosités, même des micro- infructuosités du réseau d'acier et de commencer à interagir au niveau moléculaire avec l'acier. Et ça, ça peut le fragiliser. C'est un phénomène qui est connu. C'est le phénomène de embrittlement en anglais, de fragilisation de l'acier.

RL : Mais selon l'étude de Gang, si on peut éviter des pressions, par exemple pour un réseau à 84 bar, c'est la pression maximum pour nos canalisations de gaz naturel, si on exploite ces canalisations à 60 bar par exemple, et si on fait en sorte que la demande, pas que la demande, mais que la pression ne fluctue pas trop à l'intérieur de cette canalisation, ça ne pose absolument aucun souci de réutiliser des canalisations existantes. Donc ça, c'est un message qui est assez positif. Sachant qu'en parallèle, on travaille aussi sur ce qu'on appelle les inhibiteurs. Donc ça, c'est aussi assez prometteur. Ce sont des molécules, ce ne sont pas des molécules exotiques, ça peut être un peu quelques ppm d'oxygène, ça peut être quelques ppm de CO, donc de monoxyde de carbone, qui annulent complètement cette fragilisation de l'acier.

AD : Qui sont mélangées à l'hydrogène, c'est ça ? Tout à fait, oui.

RL : Alors, il faut savoir que dans le passé, je ne l'ai pas connu ce passé, mais avant 1966, l'épopée du gaz naturel en Belgique, ça commence en 1966 avec le gaz du Grand Nergue, des Pays-Bas, avant ce moment-là, on craquait en Belgique du gaz naturel dans ce qu'on appelait des centrales gazières. Il y en avait dans le sud du pays, il y en avait à Bruxelles, il y en avait à Anvers. Et donc, on créait un espèce de gaz synthétique. Ce gaz synthétique, il contenait entre 40 et 60% d'hydrogène, il y avait un peu de méthane, mais il y avait aussi du CO, donc du monoxyde de carbone, et c'était transporté dans des canalisations en fonte. Alors, tu dois savoir que la canalisation en front, c'est un peu le cauchemar pour transporter de l'hydrogène parce que c'est vraiment une qualité qui est la plus sensible à cette fragilisation. Or, il n'y a jamais eu de souci dans le passé. Pourquoi ? Parce qu'on transportait un certain pourcentage de monoxyde de carbone qui annulait ce phénomène de fragilisation. Donc voilà, c'est entre guillemets une technique éprouvée.

AD : Ok, donc il a fait ses preuves. On arrive tout doucement à la fin, il est 10h, donc je vais vous libérer. En tout cas, merci beaucoup d'avoir répondu à mes questions.

AD : J'imagine que si j'ai d'autres petites questions, je peux vous envoyer un mail ou si j'ai une petite précision.

RL : Maintenant, je ne sais pas si tu as déjà eu accès aux documents stratégie, état belge, etc. Sinon, je peux te faire aussi un petit mail avec certains documents utiles.

AD : J'ai eu accès à beaucoup de documents, mais peut-être qu'il y en aura d'autres. Oui, je veux bien, si vous en avez sous la main. Et vous avez parlé aussi de l'étude de l'Université de Gand, à propos des changements, des évolutions de canalisation. Vous savez si c'est une étude publique ?

RL : Elle n'est pas encore terminée.

AD : Ah ok, d'accord.

RL : On l'a commencé, c'est une étude qui va durer 4 ans. Donc normalement, cette étude devrait être terminée au mois de novembre de cette année. Maintenant, il y a effectivement des études qui ont été réalisées. Et là, je pense que ça doit être quand même publique, notamment par l'Allemagne. Je pense que le document est disponible en anglais. Donc, ils ont fait aussi ce mapping en Allemagne. Et ils sont arrivés aux mêmes conclusions.

AD : Ok, d'accord. Donc ça, je peux regarder si je retrouve la compatibilité. Parce que j'ai déjà trouvé des documents à ce sujet.

RL : C'est la raison pour laquelle les premiers kilomètres de notre dorsale hydrogène, ce sera des nouvelles canalisations. Ce Gand-Anvers, c'est vraiment une nouvelle canalisation. Donc je vais noter stratégie belge. Éventuellement, je peux te mettre aussi la vision long terme de notre réseau hydrogène.

AD : Ça, je pense que j'ai déjà vu sur votre site.

RL : Oui, effectivement, il est dispo. Et alors, ce que je vais aussi peut-être te mettre à disposition, c'est le lien vers l'étude. Donc, on a réalisé une étude en collaboration avec l'Université de Liège. Et puis, on l'a reprise à notre compte. On l'a un peu étendue, qui montre en fait le rôle de l'hydrogène à l'horizon 2050. Et qui montre en fait que le système antimolécule fonctionne au niveau des pays bordant la mer du Nord. Il y a deux documents sur notre site, je vais t'envoyer le lien. Il y en a un qui est à mon avis suffisant pour toi, c'est le Executive Summary. Ça fait 10-15 pages, je pense, avec pas mal de graphiques. Et qui est assez facile à lire.

AD : Merci beaucoup, c'est gentil.

RL : Ok, écoute, je vais t'envoyer tout ça. Et effectivement, comme tu dis, si tu as des questions supplémentaires ou quoi, tu n'hésites pas à m'envoyer un petit mail, il n'y a aucun problème.

AD : Ça va, merci beaucoup, c'est gentil.

RL : Il n'y a pas de quoi. Bonne journée, merci.

AD : Également, au revoir. Au revoir et merci beaucoup.

Appendix C: Computer model in Pyomo (In French)

```python
from __future__ import annotations
from ast import mod
from xml.parsers.expat import model
import pandas as pd
from pathlib import Path
from statistics import mean
from typing import Dict, Any
import matplotlib.pyplot as plt
from pyomo.environ import (
    ConcreteModel, Set, Param, Var, NonNegativeReals, Objective, Constraint,
    minimize, value, SolverFactory
)
import numpy as np

KG_TO_TWH = 3.333e-8           # 1 kg H2 => 3.333e-8 TWh (LHV)
TWH_TO_KG = 1 / KG_TO_TWH
EURKG_TO_EURTWH = TWH_TO_KG
HOURS_YEAR = 8760
MW_TO_TWH = HOURS_YEAR / 1e6    # 0.00876 TWh par MW à 100 % CF
CAPACITY_FACTOR = 0.9           # 90 % d'utilisation théorique


# 2. LECTURE DES DONNÉES ------------------------------------

def load_data(excel_path: str | Path) -> Dict[str, Any]:
    df = pd.read_excel(excel_path)
    data: Dict[str, Any] = {}
    for _, row in df.iterrows():
        key = row["Nom de la donnée"].strip()
        raw = str(row["Valeur (à remplir)"]).replace(" ", "")  # remove NBSP
        if "-" in raw:
            low, high = map(float, raw.split("-"))
            data[key] = mean([low, high])
        else:
            try:
                data[key] = float(raw)
            except ValueError:
                data[key] = raw

    # ==== Construction des données par année/snapshot ====
    YEARS = [2035, 2050]
    SNAPS = ['ete', 'hiver']

    # -- Demande H2 (TWh par snapshot) --
    demande_H2 = {}
    for y in YEARS:
        total = data.pop(f"Demande H2 totale {y} (TWh/an)")
        part_ete = data["Part demande H2 été (%)"] / 100
        part_hiver = data["Part demande H2 hiver (%)"] / 100
        demande_H2[(y, 'ete')] = total * part_ete
        demande_H2[(y, 'hiver')] = total * part_hiver
    data["Demande H2"] = demande_H2

        # --- Définir les scénarios SRO (central, bas, haut) ---
    SCENARIOS = ["central", "bas", "haut"]
    data["SCENARIOS"] = SCENARIOS

    demande_SRO = {}
    for scen in SCENARIOS:
        for y in YEARS:
            for s in SNAPS:
                base = demande_H2[(y, s)]
                if scen == "central":
                    demande_SRO[(scen, y, s)] = base
                elif scen == "haut":
                    demande_SRO[(scen, y, s)] = base * 1.3
                elif scen == "bas":
                    demande_SRO[(scen, y, s)] = base * 0.7
    data["Demande SRO"] = demande_SRO

    # -- Potentiel ENR (TWh par snapshot) --
    potentiel_ENR = {}
    for y in YEARS:
        total_enr = data.pop(f"Potentiel ENR total {y} (TWh/an)")
        part_enr_ete = data["Part potentiel ENR été (%)"] / 100
        part_enr_hiver = data["Part potentiel ENR hiver (%)"] / 100
        potentiel_ENR[(y, 'ete')] = total_enr * part_enr_ete
        potentiel_ENR[(y, 'hiver')] = total_enr * part_enr_hiver
    data["Potentiel ENR"] = potentiel_ENR

    # -- Quota vert par année (fraction) --
    data["Quota vert"] = {
        2035: data.pop("Quota vert 2035 (%)") / 100,
        2050: data.pop("Quota vert 2050 (%)") / 100
    }

    # -- Coût élec électrolyseur par année (€/TWh) --
    data["Coût élec électrolyseur (€/TWh)"] = {
        2035: data.pop("Coût électricité électrolyseur 2035 (€/MWh)") * 1_000_000,
        2050: data.pop("Coût électricité électrolyseur 2050 (€/MWh)") * 1_000_000
    }
```

```python
    # -- Conversion des coûts/paramètres unitaires en €/TWh ou TWh si nécessaire --
    data["CAPEX stockage H2 (€/TWh)"] = data["CAPEX stockage H2 (€/kg)"] * EURKG_TO_EURTWH
    data["OPEX stockage H2 (€/TWh/an)"] = data["OPEX stockage H2 (€/kg/an)"] * EURKG_TO_EURTWH
    data["Capacité max stockage (TWh)"] = data["Capacité max stockage (kg)"] * KG_TO_TWH

    data["OPEX SMR-CCS (€/TWh)"] = data["OPEX SMR-CCS (€/kg H2)"] * EURKG_TO_EURTWH
    data["Coût import H2 (€/TWh)"] = mean([float(v) for v in str(data["Coût import H2 (€/kg)"]).split('-')]) * EURKG_TO_EURTWH \
        if isinstance(data["Coût import H2 (€/kg)"], str) and "-" in str(data["Coût import H2 (€/kg)"]) \
        else data["Coût import H2 (€/kg)"] * EURKG_TO_EURTWH

    data["Limite importation (kg/an)"] = mean([float(v.replace("E", "e")) for v in str(data["Limite importation (kg/an)"]).split('-')]) \
        if isinstance(data["Limite importation (kg/an)"], str) and "-" in str(data["Limite importation (kg/an)"]) \
        else float(data["Limite importation (kg/an)"])
    data["Limite importation (TWh/an)"] = data["Limite importation (kg/an)"] * KG_TO_TWH

    data["Limite importation (TWh/an)"] = {
    2035: float(data.pop("Limite importation 2035 (TWh/an)")),
    2050: float(data.pop("Limite importation 2050 (TWh/an)")),
    }

    data["Emissions SMR-CCS (kgCO2/kgH2)"] = float(data["Emissions SMR-CCS (kgCO2/kgH2)"])
    data["Seuil émissions (tCO2)"] = {
        2035: float(data["Seuil émissions 2035 (tCO2)"]),
        2050: float(data["Seuil émissions 2050 (tCO2)"]),
    }

    data["Stock de sécurité (TWh)"] = {
        2035: float(data["Stock de sécurité 2035 (kg)"]) * KG_TO_TWH,
        2050: float(data["Stock de sécurité 2050 (kg)"]) * KG_TO_TWH,
    }
    return data

# 3. MODÈLE PYOMO --------------------------------------------

def build_model(d: Dict[str, Any]) -> ConcreteModel:
    m = ConcreteModel(name="Belgium_H2_Simple_Snapshots")

    m.Y = Set(initialize=[2035, 2050])             # Années
    m.S = Set(initialize=['ete', 'hiver'])         # Snapshots
    m.P = Set(initialize=["Electrolyser", "SMR_CCS"])
    m.Scenarios = Set(initialize=d["SCENARIOS"])  # Scénarios SRO

    # CAPEX/OPEX/efficacités
    m.capex_prod = Param(m.P, initialize={
        "Electrolyser": d["CAPEX électrolyseur (€/MW)"],
        "SMR_CCS": d["CAPEX SMR-CCS (€/MW_H2)"]
    })
    m.opex_prod = Param(m.P, initialize={
        "Electrolyser": d["OPEX électrolyseur (€/MW/an)"],
        "SMR_CCS": d["OPEX SMR-CCS (€/kg H2)"]
    })
    m.eff_prod = Param(m.P, initialize={
        "Electrolyser": d["Efficacité électrolyseur (%)"] / 100.0,
        "SMR_CCS": 0.65
    })

    # Stockage H2 (en TWh)
    m.capex_store = Param(initialize=d["CAPEX stockage H2 (€/TWh)"])
    m.opex_store = Param(initialize=d["OPEX stockage H2 (€/TWh/an)"])
    m.cap_max_store = Param(initialize=d["Capacité max stockage (TWh)"])
    m.store_eff = Param(initialize=d["Rendement stockage (%)"] / 100.0)
    m.co2_price = Param(initialize=d["Prix CO2 (€/tCO2)"])

    # Demande et potentiel ENR (TWh)
    m.demand = Param(m.Y, m.S, initialize=d["Demande H2"])
    m.potentiel_enr = Param(m.Y, m.S, initialize=d["Potentiel ENR"])
    m.quota_vert = Param(m.Y, initialize=d["Quota vert"])
    m.cost_import = Param(initialize=d["Coût import H2 (€/TWh)"])

    # Coût variable electro (par année)
    def opex_var_init(mod, p, y):
        if p == "Electrolyser":
            return d["Coût élec électrolyseur (€/TWh)"][y]
        else:
            return d["OPEX SMR-CCS (€/TWh)"]
    m.opex_var = Param(m.P, m.Y, initialize=opex_var_init)

    # ----- Variables (en TWh pour les flux, en MW/année pour CapProd) -----
    m.CapProd = Var(m.P, m.Y, within=NonNegativeReals)              # MW installés (par an)
    m.CapStore = Var(m.Y, within=NonNegativeReals)                  # Capacité stockage (TWh)
    m.Prod = Var(m.P, m.Y, m.S, within=NonNegativeReals)            # Prod H2 par snapshot (TWh)
    m.Import = Var(m.Y, m.S, within=NonNegativeReals)               # Import par snapshot (TWh)
    m.StoreIn = Var(m.Y, m.S, within=NonNegativeReals)              # Stockage par snapshot (TWh)
    m.StoreOut = Var(m.Y, m.S, within=NonNegativeReals)             # Destockage par snapshot (TWh)
    m.StockLevel = Var(m.Y, m.S, domain=NonNegativeReals)

    # ----- Objectif -----
    def total_cost_rule(mod):
        capex = sum(mod.capex_prod[p] * mod.CapProd[p, y] for p in mod.P for y in mod.Y)
        capex += sum(mod.capex_store * mod.CapStore[y] for y in mod.Y)
```

```
        opex = sum(mod.opex_prod["Electrolyser"] * mod.CapProd["Electrolyser", y] for y in mod.Y)
        opex += sum(mod.opex_prod["SMR_CCS"] * mod.CapProd["SMR_CCS", y] for y in mod.Y)
        opex += sum(mod.opex_store * mod.CapStore[y] for y in mod.Y)
        opex += sum(mod.opex_var[p, y] * mod.Prod[p, y, s] for p in mod.P for y in mod.Y for s in mod.S)

        import_cost = sum(mod.cost_import * mod.Import[y, s] for y in mod.Y for s in mod.S)

        return capex + opex + import_cost

    m.Obj = Objective(rule=total_cost_rule, sense=minimize)

    # ----- Contraintes principales -----

    def prod_cap_rule(mod, p, y, s):
        return mod.Prod[p, y, s] <= CAPACITY_FACTOR * MW_TO_TWH * mod.CapProd[p, y]
    m.ProdCapacity = Constraint(m.P, m.Y, m.S, rule=prod_cap_rule)

    # 2. Demande satisfaite (par snapshot)
    def demand_rule(mod, scen, y, s):
        return (
            sum(mod.Prod[p, y, s] for p in mod.P)
            + mod.Import[y, s]
            + mod.StoreOut[y, s]
            >= d["Demande SRO"][(scen, y, s)]
        )
    m.Demand = Constraint(m.Scenarios, m.Y, m.S, rule=demand_rule)

    # 3. Bilan stockage
    def storage_balance(mod, y):
        return mod.StoreIn[y, 'ete'] + mod.StoreIn[y, 'hiver'] \
             - mod.StoreOut[y, 'ete'] - mod.StoreOut[y, 'hiver'] == 0
    m.StorageBalance = Constraint(m.Y, rule=storage_balance)

    # 4. Capacité de stockage (TWh)
    def store_cap_rule(mod, y, s):
        return mod.StoreIn[y, s] <= mod.CapStore[y]
    m.StoreCap = Constraint(m.Y, m.S, rule=store_cap_rule)

    # 5. Capacité de stockage : niveau de stock ne peut exéder la capacité installée
    def stocklevel_capacity_rule(mod, y, s):
        return mod.StockLevel[y, s] <= mod.CapStore[y]
    m.StockLevelCap = Constraint(m.Y, m.S, rule=stocklevel_capacity_rule)

    # 6. Quota vert (somme annuelle de l'électrolyseur >= quota * somme demande)
    def green_quota_rule(mod, y):
        return sum(mod.Prod["Electrolyser", y, s] for s in mod.S) >= mod.quota_vert[y] * sum(mod.demand[y, s] for s in mod.S)
    m.GreenQuota = Constraint(m.Y, rule=green_quota_rule)

    # 7. Limite ENR pour la prod électrolyseur dans chaque snapshot
    def green_limit_rule(mod, y, s):
        return mod.Prod["Electrolyser", y, s] <= mod.potentiel_enr[y, s]
    m.GreenLimit = Constraint(m.Y, m.S, rule=green_limit_rule)

    # 8. Limite importation H2
    def import_limit_rule(mod, y):
        return sum(mod.Import[y, s] for s in mod.S) <= d["Limite importation (TWh/an)"][y]
    m.ImportLimit = Constraint(m.Y, rule=import_limit_rule)

    def co2_limit_rule(mod, y):
        emissions_annuelles_kg = sum(mod.Prod["SMR_CCS", y, s] for s in mod.S) / KG_TO_TWH * d["Emissions SMR-CCS (kgCO2/kgH2)"]
        return emissions_annuelles_kg / 1000 <= d["Seuil émissions (tCO2)"][y]
    m.CO2Limit = Constraint(m.Y, rule=co2_limit_rule)

    def stock_balance_rule(mod, y, s):
        if s == "ete":
            return mod.StockLevel[y, s] == mod.StoreIn[y, s] - mod.StoreOut[y, s]
        else:
            return mod.StockLevel[y, s] == mod.StockLevel[y, "ete"] + mod.StoreIn[y, s] - mod.StoreOut[y, s]
    m.StockBalance = Constraint(m.Y, m.S, rule=stock_balance_rule)

    def stock_securite_rule(mod, y):
        return mod.StockLevel[y, "ete"] >= d["Stock de sécurité (TWh)"][y]
    m.StockSecurite = Constraint(m.Y, rule=stock_securite_rule)

    return m

# 4. MAIN ROUTINE --------------------------------------------

def main():
    excel_file = "Data - H2.xlsx"
    data = load_data(excel_file)
    model = build_model(data)

    solver = SolverFactory("cbc")
    result = solver.solve(model, tee=True)

    print("\n==== Vérification de la robustesse ====")
    for scen in data["SCENARIOS"]:
        print(f"\n--- Scénario {scen} ---")
        for y in model.Y:
```

```
            for s in model.S:
                total_prod = sum(value(model.Prod[p, y, s]) for p in model.P)
                total = total_prod + value(model.Import[y, s]) + value(model.StoreOut[y, s])
                demande = data["Demande SRO"][(scen, y, s)]
                print(f"{y}-{s}: disponible = {total:.2f} TWh, demande = {demande:.2f} TWh")

    print("\n==== Résultats ====")
    for y in model.Y:
        for s in model.S:
            print(f"\nAnnée {y} - {s.capitalize()}")
            for p in model.P:
                print(f"  Prod({p}) = {value(model.Prod[p, y, s]):.2f} TWh")
            print(f"  Import = {value(model.Import[y, s]):.2f} TWh")
            print(f"  StoreIn = {value(model.StoreIn[y, s]):.2f} TWh")
            print(f"  StoreOut = {value(model.StoreOut[y, s]):.2f} TWh")
            print(f"Stock à la fin de l'été ({y}) = {value(model.StockLevel[y, 'ete']):.2f} TWh")
            print(f"Stock à la fin de l'hiver ({y}) = {value(model.StockLevel[y, 'hiver']):.2f} TWh")
        for p in model.P:
            print(f"Capacité installée {p} ({y}) = {value(model.CapProd[p, y]):.2f} MW")
        print(f"Capacité stockage ({y}) = {value(model.CapStore[y]):.2f} TWh ({value(model.CapStore[y]) * TWH_TO_KG:.0f} kg)")
        print(f"\nCoût total du système (objectif) = {model.Obj.expr():,.2f} €")

if __name__ == "__main__":
    main()
```

Abstract:

This thesis proposes a robust optimization methodology for planning Belgium's hydrogen energy system by 2050. The objective is to assess how to efficiently meet a growing demand for low-carbon hydrogen while complying with national and European environmental constraints, notably the renewable hydrogen quota set at 95%. The developed model, based on a Mixed-Integer Linear Programming (MILP) formulation under robust constraints (SRO), compares a classical deterministic approach to a robust approach that explicitly accounts for uncertainties in future demand. The results show that a robust strategy featuring a moderate oversizing of electrolysis capacity (approximately +20%) and seasonal storage (approximately +25%) would ensure hydrogen supply security even under a high-demand scenario (+30%), with a limited additional cost of around 10% compared to the deterministic solution. The sensitivity analysis further reveals that the system's optimal configuration is strongly influenced by political objectives (renewable quota) and the availability of local renewable energy resources. Thus, a robust approach appears particularly relevant for ensuring the long-term resilience and economic sustainability of Belgium's hydrogen system in a context of major uncertainties surrounding the energy and climate transition.

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