# Integration of nuclear energy in the energy system

Scenario analysis for the Dutch energy system

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## Scenario analysis for the Dutch energy system

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# Contents

# Executive summary

**Nuclear energy can contribute to a future sustainable energy system in the Netherlands. Research conducted by TNO and NRG PALLAS explored how nuclear energy might be integrated into the energy system. The findings suggest that, in pursuit of a climate-neutral energy system with the lowest societal costs, there is a possible viable role for both large-scale nuclear power plants (NPPs) and small modular reactors (SMRs). Large NPPs offer the advantage of diversifying electricity generation alongside renewable sources like wind and solar. Additional electricity can support further electrification of the energy system, leading to greater overall cost efficiency. SMRs, on the other hand, are particularly promising for supplying industrial heat. However, the attractiveness of new nuclear plants depends on several uncertainties, such as investment costs, future electricity demand, and the dynamics of electricity and hydrogen imports and exports. From an electricity market perspective, this study finds that integrating nuclear energy into the generation mix lowers average electricity prices. However, at these price levels, revenue generated is insufficient to offset the investment costs of nuclear power plants, making additional financial support necessary. The study also examined the implications of expanding nuclear capacity for the Netherlands' nuclear infrastructure. An increase in nuclear power capacity will affect both the demand for nuclear fuel and nuclear waste management effort.**

### Context and motivation

The Dutch government acknowledges the potential role of nuclear energy in achieving a climate-neutral energy system. It plans to extend the operational life of the existing Borssele nuclear power plant and to facilitate the construction of two to four new large-scale NPPs. Additionally, the government supports the development and deployment of SMRs.

To support the expansion of nuclear energy, the Netherlands must strengthen its nuclear knowledge base and infrastructure. As part of a broader program focused on knowledge and human capital development, the Ministry of Climate Policy and Green Growth has funded a research program by TNO and NRG PALLAS. Amongst the aims of the program are the advancement of expertise on the integration of nuclear in the energy system and the improvement of understanding public perceptions surrounding nuclear energy.

### Aim and methodology

This report outlines the methodology and findings of the study on the integration of nuclear energy into the Dutch energy system. The study has two main objectives: first, to advance research methods, particularly by adapting energy system and market models to enable comprehensive analyses of the potential impact of nuclear energy on the energy system. Second, it aims to generate new insights and, more specifically, to address the following eight research questions:

1. What will be the future electricity demand and the possible share of nuclear electricity in the electricity mix?
2. What effect does adding nuclear energy to the energy mix have on final energy use?
3. How will nuclear energy influence energy import dependence?
4. What effect does integrating nuclear energy have on the costs of the energy system?

5. What is the impact of nuclear integration on the need for flexibility in the electricity system?
6. What are the consequences of nuclear integration on energy market prices?
7. How will NPPs be operated in the future electricity market, what limits the flexible operation of nuclear reactors and how can social and private (i.e. investor) costs and benefits be balanced?
8. What is the impact of the projected expansion of nuclear energy on the nuclear infrastructure in the Netherlands, i.e. on fuel supply and nuclear waste management?

This study adopts two complementary perspectives. The first is a total energy system perspective, focused on the question: “Is nuclear energy economically viable within a climate-neutral Dutch energy system from a societal perspective?” To address this and the first four research questions, an integrated energy system model for the Netherlands was used.

The second perspective is that of the energy market, centred on the question: “Is investment in and operation of NPPs attractive for private companies?” This was explored through an energy market model analysis, supported by qualitative assessments, to answer research questions 5 through 7.

The deployment of new nuclear reactors introduces changes to the nuclear fuel cycle. To address research question 8, the study quantifies the implications for the broader nuclear ecosystem, both in the front-end (activities before nuclear fuel enters the reactor) and back-end (activities after spent nuclear fuel leaves the reactor).

All analyses in this study are based on two energy scenarios previously developed by TNO: ADAPT and TRANSFORM. Both scenarios aim for a climate-neutral energy system by 2050, but they differ in societal ambition and approach. In the ADAPT scenario, the current lifestyle and industrial structure are largely maintained. Fossil fuels may still be used in combination with carbon capture and storage (CCS). There are limited sustainability efforts focused on feedstocks for chemicals, plastics, and bunker fuels for international aviation and shipping. In contrast, the TRANSFORM scenario envisions a society that is intrinsically motivated to achieve sustainability. It assumes lifestyle changes among consumers and a broad transformation of the energy system and industry, with only limited reliance on CCS. In this scenario, feedstocks and fuels are also made sustainable. The analyses in this study compare both scenarios with and without the addition of new nuclear power plants (NPPs) and small modular reactors (SMRs) – both of which being Light Water Reactors (LWRs) –, highlighting the impact of nuclear energy on the overall energy system.

In parallel with this study, the ministry of KGG commissioned TNO to conduct a supplementary analysis focused on costs of the energy system. Although, this system costs analysis uses the same approach, several key differences lead to varying outcomes in terms of system costs. One major distinction is that the present study assumes nuclear energy integration enables additional electricity production within the system. In contrast, the system cost study assumes equal electricity production levels in scenarios with and without nuclear energy. Moreover, the supplementary study provides a more detailed examination of cost differences, including multiple sensitivity analyses that influence the outcomes. The report “Systeemkostenanalyse kernenergie” will be published concurrently with this study.

It is important to note that neither study seeks to present a comprehensive assessment of all the advantages and disadvantages of nuclear energy within a future Dutch energy system. This requires a broader evaluation of externalities and societal benefits.

### Key findings integrated energy system analysis

The key findings of the integrated energy system analyses addressing research questions 1 to 4 are summarized below:

1. **When renewable energy is utilized nearly to its full potential and new nuclear power plants are added to the energy system, a greater electricity demand can be met.**
   The electrification of heating – in industry and built environment – and mobility, along with the deployment of electrolysers for hydrogen production, is driving electricity demand increase. Incorporating nuclear energy into the Dutch energy system supports further electrification. Without new NPPs, the future Dutch energy system relies heavily on wind and solar energy, constrained by spatial and societal limits. Adding nuclear energy introduces a new source of $CO_2$-free electricity, enabling the system to meet a larger demand (depending on the scenario, 7% to 14% more than in a system without new NPPs). Some of this electricity is used for hydrogen production. Some of the electricity and hydrogen are exported making the optimal nuclear capacity sensitive to the trade of electricity and hydrogen with neighbouring countries.

   **With the deployment of four new large NPPs (total 6 $GW_e$) and SMRs (total 2.1 $GW_e$), nuclear energy is projected to supply between 10.5% and 14.5% of the electricity mix by 2050.**
   Depending on the scenario, nuclear energy is expected to generate between 56 TWh (14.5%) to 59 TWh (10.5%) of electricity in 2050. For comparison, in 2024, 3.4 TWh nuclear electricity was produced by the existing Borssele NPP – that was 2.8% of total electricity production. In the scenarios the contribution of SMRs to total nuclear electricity production remains modest since, as a result of cost-optimisation, SMRs are primarily deployed for industrial process heat rather than for electricity generation. Wind and solar remain the dominant sources of electricity. In scenarios with new NPPs, wind and solar account for 84% to 88% of the electricity mix in 2050. The cost-optimal level of nuclear deployment is sensitive to factors such as rising nuclear investment costs or shifts in electricity and hydrogen trade with neighbouring countries. These dynamics can result in an energy system with no or fewer new nuclear power plants.

2. **Integrating nuclear energy into the energy system facilitates greater electrification of heat demand in buildings, expansion of hydrogen production via electrolysis, and enables the direct use of nuclear heat in industrial processes.**
   - *Built environment*: by providing additional electricity from nuclear power plants, it becomes possible to increase the use of electric heating in the built environment. As a result of cost optimization, heat demand rises partly due to reduced investment in home insulation.
   - *Industry:* SMRs are expected to play a significant role in supplying industrial process heat and providing electricity to specific regions. The deployment of SMRs shows resilience to changes in assumptions and boundary conditions. Even if SMR investment costs are doubled, the total installed capacity decreases by only one-third, highlighting the strong competitiveness of nuclear heat.
   - *Hydrogen*: In a cost-optimized energy system, additional electricity from nuclear power enables increased hydrogen production through electrolysis. This additional hydrogen is primarily used to produce synthetic fuels for aviation and maritime transport (i.e., bunker fuels), reducing reliance on biofuels in these sectors.

3. **An energy system that includes nuclear power shows reduced dependence on fossil fuels compared to a system without nuclear energy. However, the system does become more dependent on imported uranium.**

The integration of nuclear energy leads to a decline in fossil fuel imports in 2050 of approximately 16% in both scenario's, while biomass imports remain unchanged to their assumed maximum levels. Adding nuclear energy increases the total primary energy supply by 13% in ADAPT and 14% in TRANSFORM by 2050. This increase is largely due to the relatively low conversion efficiency of the nuclear steam cycle, meaning the rise in primary energy is significantly greater than the increase in final energy consumption. As a result, the share of fossil fuels in the total primary energy mix declines more sharply than the absolute volume. Currently, fossil fuels account for over 80% of primary energy supply. In the ADAPT scenario, fossil energy remains part of the mix in 2050 due to the use of CCS and limited sustainability ambitions for feedstocks and bunker fuels. Without new nuclear capacity, fossil fuels make up 7% (TRANSFORM) and 31% (ADAPT) of the primary energy mix. With new nuclear capacity, this drops to 5% and 23%, respectively.

**The development of new nuclear production capacity can influence the exchange of electricity and hydrogen with neighbouring countries.**
The Dutch energy system is electrically connected with neighbouring countries. It is anticipated that in future the Netherlands will also be connected to Germany and Belgium via hydrogen pipelines. The integration of nuclear energy into the national energy mix may affect both the import and export dynamics of electricity and hydrogen.

- *Electricity*: In scenarios with new nuclear energy, the Netherlands could become either a net exporter or a net importer of electricity, depending on the scenario. In the scenario with net imports, electricity imports decline — and may even shift to net exports — due to lower electricity demand when no new nuclear power plants are developed. If no new nuclear power plants are built, only the volume changes in the scenario with net export.
- *Hydrogen*: The Netherlands could become either a net importer or exporter of hydrogen, depending on the scenario and the level of nuclear capacity. While the presence or absence of new nuclear power plants does not fundamentally alter this dynamic, it does influence the magnitude of hydrogen flows.

4. **In an integrated system model, energy scenarios that include nuclear power can result in lower annual system costs compared to scenarios without nuclear power. New nuclear power plants result in increased costs for electricity production, but this is more than offset by lower costs on the demand side of the energy system. However, the cost advantage is highly dependent on the broader context of each scenario and on technology choices made independently in each sector.**
Model analysis indicates that annual system costs are 1.6% to 1.7% lower – depending on the scenario – when new nuclear capacity is included. These results are influenced by factors such as nuclear investment costs, electricity demand, cross-border energy trade, and electricity grid reinforcement.
In scenarios with nuclear capacity in addition to renewable electricity supply, electricity is more widely used across demand sectors. This leads in these cost optimized scenarios to the adoption of less energy-efficient but lower-cost technologies such as electric boilers instead of heat pumps, or air-source heat pumps instead of ground-source ones. Moreover, both scenarios show cost savings in building insulation when nuclear energy is included, as fewer investments are made in measures like home insulation. However,

technology choices made in the end-user sector, whether or not influenced by energy policy, are made independently of those in electricity production.
Another major factor influencing system costs is the shift in energy imports and exports, particularly hydrogen, and to a lesser extent, natural gas.

### Key findings energy market analysis

The key findings of the energy market analyses addressing research questions 5 to 7 are summarized below:

5. **In scenarios without nuclear energy, the demand for system flexibility increases, primarily due to a higher share of solar PV. This greater need for short-term flexibility is addressed through expanded energy storage capacity.**
   The analysis focused on two sources of flexibility: energy storage and hydrogen production via electrolysis. In non-nuclear scenarios, electricity production is lower, despite higher solar PV generation. This results in lower electrolysis capacity than in comparable nuclear scenarios. As a result, electrolysers contribute less to system flexibility. To compensate, non-nuclear scenarios (both ADAPT and TRANSFORM) rely more heavily on battery energy storage to meet the additional short-term flexibility requirements.

6. **Average electricity prices are lower when nuclear energy is part of the energy mix.**
   Energy scenarios that include new NPPs tend to have lower volume-weighted average electricity prices in the Netherlands compared to those without. This is primarily because NPPs have relatively low marginal costs, reducing the need to dispatch more expensive generation sources such as gas and hydrogen. These price differences also influence cross-border electricity trade. In scenarios without nuclear energy in the Netherlands, electricity imports and exports shift, which in turn affect market prices in neighbouring countries. As a result, electricity prices in surrounding regions are, according to the analysis, slightly higher compared to scenarios where nuclear energy is part of the Dutch energy mix. It should be noted that electricity market dynamics involve high uncertainty related to demand profiles, international policies, and infrastructure developments.

7. **In an electricity market dominated by variable renewable sources like wind and solar, large NPPs operate as load-following technologies rather than as base-load units. Their annual dispatch ranges from approximately 5,500 hours in 2040 to 6,500 hours in 2050.**
   The dispatch and profitability of the NPPs were assessed within an energy-only market, where revenues depend solely on electricity prices and production. In future scenarios with high shares of solar and wind, NPPs are dispatched when market prices exceed their variable production costs. These prices fluctuate significantly due to variations in electricity demand and renewable supply. Operational constraints are respected, such as ramp rates, minimum load levels, and limits on the number of ramp-up and ramp-down cycles.

   **In an electricity market heavily reliant on wind and solar, and where revenues are solely derived from market prices and electricity production (i.e. an energy-only market), annual revenues for large NPPs are insufficient to cover capital and operational costs.**
   By 2050, and based on model assumptions, projected financial shortfalls amount to –€30/MWh in ADAPT and –€36/MWh in TRANSFORM, leading to substantial annual operating losses. With a projected output of 41 TWh from large NPPs in TRANSFORM 2050, the estimated financial shortfall under applied market assumptions could amount

to approximately €1.4 billion annually, indicating that policy instruments or support mechanisms will be necessary to ensure investment viability. This analysis does not capture all real world variables such as financing structures, project-specific risks, or future policy interventions

### Key findings nuclear fuel cycle analysis

The key findings of the nuclear fuel cycle analyses addressing research question 8 are summarized below:

8. **Around 2050, Dutch reactors account for between 0.9 – 1.2% of the global demand for natural uranium.**
   The additional demand for (enriched) uranium resulting from the Dutch newbuild NPPs scenarios coincides with the expected strong growth in demand resulting from global new nuclear construction. Similar figures also apply to enrichment and conversion, important processes in the nuclear fuel production cycle. The increasing demand in the Netherlands will go hand in hand with a global trend towards more installed capacity. As a result, the production capacity for front-end goods and services will also increase.

   **Extra storage capacity is required for heat producing high level waste and non-heat producing waste from reprocessing, depending on the scenario and fuel choices.**
   Depending on the scenario and fuel choices, approximately 3100 $m^3$ to 3800 $m^3$ is required for storage of heat producing high level waste, and 171 $m^3$ of non-heat producing waste. Additionally up to 82 kilotons of depleted uranium, equivalent to around 9000 $m^3$ of $U_3O_8$, will be produced as a by-product of enrichment for Dutch reactor fuel. This requires significant expansion of existing storage and processing capacity in the Netherlands. Furthermore, there will also be an increase in the amount of low and intermediate level waste (LMRA), but this has not been analysed in this work.

   **Use of Mixed Oxide Fuel (MOX) is more beneficial on the front-end**
   Fuel cycles using MOX (thus involving reprocessing) decrease the demand for uranium mining and fuel cycle services such as enrichment. If a variant is chosen in which no reprocessing takes place, entire fuel assemblies will have to be stored, causing an increase in required storage capacity different from the current Dutch practice. Exactly how much volume needs to be stored depends on how the storage is carried out. When reprocessing is employed, significant amounts of separated uranium and plutonium are formed. Apart from using in MOX fuel, these could also be utilized in advanced reactors that are beyond the scope of this analysis.

# 1 Introduction

## 1.1 Context

*Historical development*

Since the 1960s, nuclear energy has been used to produce electricity in the Netherlands. In 1955 construction of the High Flux Reactor (HFR) in Petten started, a research reactor which is still in operation. The first operating nuclear power plant (NPP) was a 60 $MW_e$ boiling water reactor in Dodewaard (1969-1997), which was permanently shut down for economic reasons. The second NPP was pressurized water reactor (PWR) in Borssele (480 $MW_e$), connected to the grid in 1973 and is still in operation. However, the role of nuclear energy in the Dutch energy system has remained modest: in 2024 it had a share of 2.75% (CBS) in total Dutch electricity production. The fact that no more NPPs have been built in the Netherlands is due to a changing societal perception of the safety of this technology. Nuclear accidents in Harrisburg (1997), Chernobyl (1986) and Fukushima (2011) have increased safety concerns[1].

Societal and political opinions about nuclear energy have changed since then. Nuclear energy can generate $CO_2$-free energy. This makes nuclear energy a technology that can play a role in achieving a climate-neutral energy system. In Europe, new NPPs have been built (Finland) or are under construction (France, United Kingdom). Other countries are also considering building new NPPs (e.g. Poland, Czech Republic). At the same time, some countries are phasing out nuclear energy (e.g. Germany).

*Technical development*

Nuclear energy technology is under continuous development. This is illustrated in Figure 1.1. Existing NPPs can extend their operational life (Long Term Operation). And countries' nuclear energy capacity can be maintained or expanded with new large NPPs (capacity 1000-1500 $MW_e$). With these large generation III[2] nuclear reactors, the investment costs per kilowatt are governed by economics of scale. The construction of a large scale plant on a dedicated site is a large capital-intensive project and there are many examples of such projects with cost overruns, major delays and disputes between vendor and owner. With small modular nuclear reactors (SMRs, 50-500 $MW_e$), the intention is that NPP systems and components are assembled in a factory, and then transported to a site for installation. This enables production in a more controlled environment and facilitates series manufacturing of SMRs. This 'economy of numbers' approach should keep the cost development manageable. In contrast to large NPPs, SMRs are not yet commercially available in Europe or North America (Breijder, 2023) (NRG, 2023). The first commercial SMRs are expected to be in operation in Canada or the United Kingdom before 2030. Lastly, fourth generation nuclear reactors are being developed. Compared to generation III types these innovative nuclear technologies have a number of advantages, including passive safety features and improved nuclear fuel cycle (e.g. higher efficiency and less high-level radioactive waste). Most designs feature

[1] The report "Public Trust in Nuclear Energy" provides an overview of the eras of Dutch Nuclear History (Weerdt, et al., 2024)

[2] Nuclear reactors are divided into generations. The most modern reactor types on the market are Generation III with improvements in safety, operating life, fuel technology and efficiency compared to Generation II built in the 1970s and 1980s. Generation IV are reactor concepts in development from which further improvements are expected.

reactors operating at high-temperature and that are cooled with gas, molten salt or lead (IAEA, 2024) (IEA, 2024). Fourth generation NPPs are expected to come onto the market in 10 to 20 years, depending on the design (Scheepers, Haas, Roelofs, Jeeninga, & Gerdes, 2020).

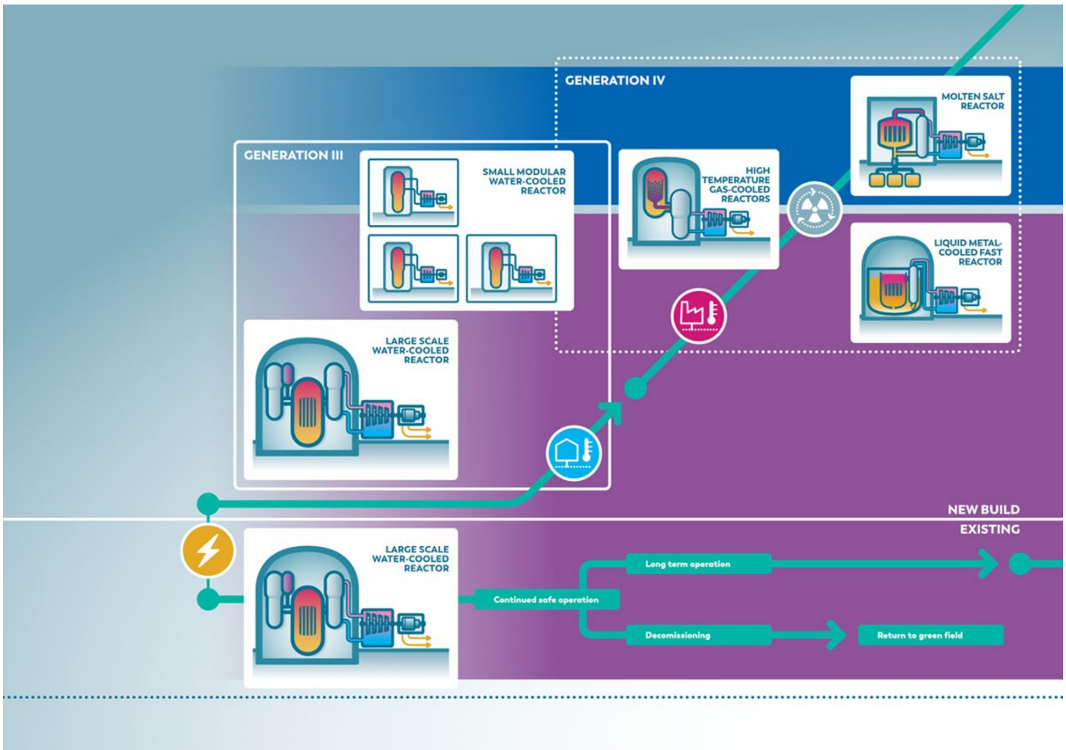


Figure 1.1: Illustration of developments of nuclear energy technology

## 1.2 Motivation

*Dutch nuclear energy policy*

The Dutch government has recognized that nuclear energy could play a role in the future Dutch climate-neutral energy system. The Rutte IV government formulated a new nuclear energy policy that will allow the Borssele NPP to remain in operation for longer and will facilitate the construction of two new large NPPs (EZK, 2023). The Schoof government has further expanded the policy intentions to include 4 large NPPs and also the application of SMRs (Dutch Government, 2024).

*Strengthening the nuclear knowledge base*

To enable the expansion of nuclear energy in the Netherlands, the Dutch nuclear knowledge base and infrastructure also need to be strengthened. For this purpose, a Multi-Year Mission-Driven Innovation Program (MMIP) Nuclear Energy has been set up, part of the Top Sector Energy, which will invest in education, research and innovation in the field of nuclear energy until 2030 (Ministry of Economic Affairs and Climate Policy, 2023).

The MMIP distinguishes two sub-programs: a human capital agenda aimed at strengthening the nuclear knowledge base and infrastructure in education and a knowledge and innovation program. This latter program consists of 8 research themes:

1. Radiation protection
2. System knowledge (integration of nuclear energy into the Dutch energy system)

3. Knowledge about nuclear reactor and fuel cycle technology
4. Reactor-related 'enabling' topics ('plant integrity', maintenance under extreme conditions, etc.)
5. High-temperature hydrogen production
6. Materials research, including using ionizing radiation
7. Processing and storage of radioactive waste and geological disposal.
8. Public perception, communication, and public support.

In anticipation of the implementation of this knowledge program, the Ministry of Climate Policy and Green Growth financed in 2024 a knowledge program by TNO and NRG PALLAS[3], aimed at knowledge building for the themes System knowledge (theme 2) and Public perception, communication, and public support (theme 8). This research report describes the approach and results of the research project “Integration of nuclear energy into the energy system”. Results of the research project “Public trust in nuclear energy” can be found in (Weerdt, et al., 2024).

*Research questions*
The aim of the project “Integration of Nuclear Energy into the Energy System” is, on the one hand, to enhance research methodologies, in particularly to make energy system and market models suitable for comprehensive nuclear energy system analyses. On the other hand, the research aims to generate new insights and provide answers to the following eight research questions (arranged according to the system to be examined):

- Energy system related questions:
  1. What will be the future electricity demand and the possible share of nuclear electricity in the electricity mix?
  2. What effect does adding nuclear energy to the energy mix have on final energy use?
  3. How will nuclear energy influence energy import dependence?
  4. What effect does integrating nuclear energy have on the costs of the energy system?
- Energy market related questions:
  5. What is the impact of nuclear integration on the need for flexibility in the electricity system?
  6. What are the consequences of nuclear integration on energy market prices?
  7. How will NPPs be operated in the future electricity market, what limits the flexible operation of nuclear reactors and how can social and private (i.e. investor) costs and benefits be balanced?
- Nuclear fuel cycle related question:
  8. What is the impact of the projected expansion of nuclear energy on the nuclear infrastructure in the Netherlands, i.e. on fuel supply and nuclear waste management?

Not all predefined research questions have been (fully) answered. A research question, concerning possible effects on the electricity grid infrastructure, which was initially also included in the present study, could not be answered due to a lack of data and suitable modelling tools. As a result, this research also leads to several recommendations for future studies.

[3] This program also finances activities of the Nuclear Academy, a collaboration of NRG-Pallas and the Delft University of Technology.

## 1.3 Approach

*Energy system analysis*
For this research two perspectives are selected. The first is the total energy system perspective, where the central question is: "Is nuclear energy (economically) attractive for a climate-neutral Dutch energy system from a societal perspective?". For answering this question and the first four research questions above, an analysis was performed with an integrated energy system model for the Netherlands.

*Energy market analysis*
The second perspective is that of the energy market. The central question is: "Is investing in and operating NPPs attractive for private companies?". In order to answer this question and related research questions 5 to 7 formulated above, an energy market model analysis was performed, supplemented with a qualitative analysis.

It should be noted that in the energy market analyses only the potential impact on market prices is considered. For investment decisions specific business case analyses are required — something that is explicitly not intended in this study.

*Nuclear fuel cycle analysis*
The deployment of new nuclear reactors goes hand in hand with a new situation in the nuclear fuel cycle. For a given future reactor fleet, an estimate can be made of the implications on the surrounding nuclear ecosystem in both the front-end (everything before fuel enters the nuclear reactor) and back-end (everything after the fuel leaves the nuclear reactor) of the fuel cycle. Metrics associated with the impact (e.g. fuel production and waste generation) are important indicators for determining whether sufficient capacity currently exists, or whether expansion of the Dutch nuclear infrastructure is needed, and whether the international market for nuclear products and services will be able to adequately meet the demands originating from the Dutch nuclear industry. To answer research question 8 a fuel cycle analysis of the Dutch nuclear reactor fleet was performed.

*Assessment of nuclear technologies and model improvement*
Before starting with model analyses, a technological assessment is performed on parameters for large NPPs and SMRs. The scope is limited to large NPPs and SMRs of generation III, based on Light Water Reactor (LWR) technology[4]. Furthermore, it is assumed that the SMRs could supply steam to industrial processes in addition to electricity. It is also investigated how NPPs and SMRs can best be represented in the energy system and the market models. In addition to adjusting the representation of nuclear reactors in the models, the procedure for soft-coupling between the two models has also been improved.

*Energy scenarios*
No new scenarios are developed in the present study. Instead, two existing energy scenarios from TNO are applied: ADAPT and TRANSFORM. These scenarios originate from a scenario study published in 2024 (Scheepers, et al., 2024). Future electricity and hydrogen demand in neighbouring countries are based upon scenarios from the Ten Year Network Development Plans (TYNDP) of the associations of European network operators ENTSO-E and ENTSOG.

*What has not been investigated*
Although this research into the integration of nuclear energy in the energy system can answer a number of questions, it does not yet provide a complete picture of the advantages

[4] Light water reactors cooled with steam, i.e. pressurized water reactors (PWRs)

and disadvantages of applying nuclear energy in a future Dutch energy system. This requires a broader analysis of the implications in the field of radiation safety, security risks (e.g. in

### System Cost Analysis Nuclear Energy

*In parallel with this study, the ministry of KGG commissioned TNO to conduct a supplementary analysis focused on system costs. This additional study builds upon the current research, using the same baseline scenarios and energy system models. However, several key differences lead to varying outcomes in terms of system costs. One major distinction is that the present study assumes nuclear energy integration enables additional electricity production within the system. In contrast, the system cost study assumes equal electricity production levels in scenarios with and without nuclear energy. Moreover, the supplementary study provides a more detailed examination of cost differences, including multiple sensitivity analyses that influence the outcomes.*
*The report System Cost Analysis Nuclear Energy* (Kooiman, Scheepers, Beres, Hakvoort, & Meeuwsen, 2025) *will be published concurrently with this study.*

relation to geopolitical developments), environmental aspects (during the entire life cycle of a nuclear reactor), proliferation risks, etc. The recommendation section of the last chapter of this report discusses this further research in more detail.

## 1.4 Reading guide

This report is structured as follows:

- Chapter **2** provides an extensive explanation of the methodology used. This chapter introduces the different quantitative models, the scenarios and variants used and the assumptions, boundary conditions and input parameters.
- The results are presented in three chapters:
  - Chapter **3** analyses the integration of nuclear energy from an integrated national energy system perspective. This chapter discusses the results of the energy system analysis and attempts to answer research questions no. 1 to 4.
  - Chapter **4** analyses the integration of key energy from a market perspective. The results of the energy market analysis are discussed as well as a qualitative analysis of the market structure. This chapter tries to find answers to research questions no. 5 to 7.
  - Chapter **5** discusses the nuclear fuel cycle analysis. This chapter provides answers to the last research question no. 8.
- Finally, Chapter **6** formulates conclusions from the different analyses and provides recommendations for further research.

This report also contains several appendices that provide background information on the various analyses performed.

# 2 Methodology

To answer the research questions formulated in Chapter 1, existing model tools are used. These models are the integrated energy system model OPERA that describes the Dutch energy system, the European energy market model COMPETES-TNO, and a model for analysing the nuclear fuel cycle. A description of the models used is given in Section 2.1. Where necessary, the model tools have been adapted for modelling nuclear power and heat production. The soft-linking between the OPERA model and COMPETES-TNO is also discussed in Section 2.1. Existing energy scenarios have been used for the analyses. These are explained in Section 2.2. Section 2.3 provides an overview of the input parameters used in the energy system and energy market models, with reference to the appendices for the input data. Finally, Section 2.4 explains the parameters used for the nuclear fuel cycle analysis.

## 2.1 Model tools

### 2.1.1 OPERA

The present study builds on an earlier study using the OPERA model (Scheepers, et al., 2024). Another TNO model is also available. A comparison between the two models was performed; see Box 1.

OPERA is an integrated energy system model for the Netherlands. Taking into account a greenhouse gas emission target, the model calculates an energy system for a specific year that meets the service demand (e.g. heating a certain number of houses and buildings, producing industrial products, transporting people and goods, etc.). The model selects (endogenously) which technologies are most cost-efficient and calculates the energy supply mix and the energy demand mix based on the cost optimal deployment of these technologies. I.e. the model determines an energy system that has the lowest social costs. See for further details: (Stralen, Dalla Longa, Daniëls, Smekens, & Zwaan, 2020).

The OPERA model is shown schematically in Figure 2.1. Input parameters used by OPERA are:

- Maximum greenhouse gas emissions.
- Service demand levels that are drivers of energy demand, such as building surface area, size of mobility demand and production of industrial products.
- Techno-economic data of the technology options.
- Price of imported energy commodities and feedstocks.
- Specific constraints on the use of technologies, such as maximum capacity for wind and solar energy production, maximum $CO_2$ storage per year and maximum NPP capacity. These values are determined based on physical constraints, public acceptance, policy objectives, etc.

The OPERA model provides the following results:
- Physical results: mix of energy supply and demand (total and per sector), technologies used (e.g. installed capacity, full load hours), import and export of energy (e.g. fossil energy, biomass, electricity, hydrogen), residual greenhouse gas emissions.
- Economic results: system costs and annual investments (total and per sector) and shadow prices (based on marginal costs for $CO_2$ reduction and production of electricity and hydrogen).

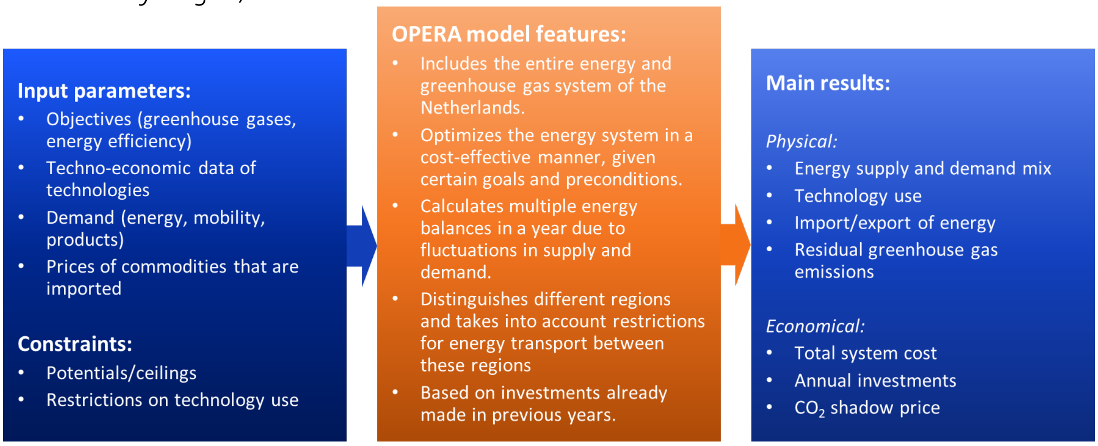


Figure 2.1: Schematic representation of the OPERA model.

The model takes into account the fluctuating energy demand during a year and the variable energy production from wind and sun, based on data for a representative year. In doing so, supply and demand are balanced for each time period, whereby options such as demand management and energy storage are also used, and energy is imported or exported from and to neighbouring countries.

The model distinguishes different regions in the Netherlands: 7 regions on land (each industrial cluster falls into a separate region) and 7 regions on the North Sea with distinctive wind regimes and distances to the coast, see Figure 2.2. Heat cannot be exchanged between regions, because long-distance transport of heat is too expensive and leads to considerable heat losses. Electricity can be transported between regions and also to and from neighbouring countries. For transport over the high-voltage grid and over the interconnections with neighbouring countries, capacity limitations are taken into account. When distinguishing between regions, the number of time periods in a year is limited to 85 time slices, where each time slice has a corresponding energy supply and demand. A model analysis can also be performed for 8760 periods per year (i.e. hours), but then no distinction can be made between regions due to computational limitations.

The model uses a myopic approach: for each subsequent year for which an energy system is calculated, the model takes into account the assets already present from the previous period based on the technical lifetime of these assets. The model determines whether additional capacity must be invested to meet the demand.

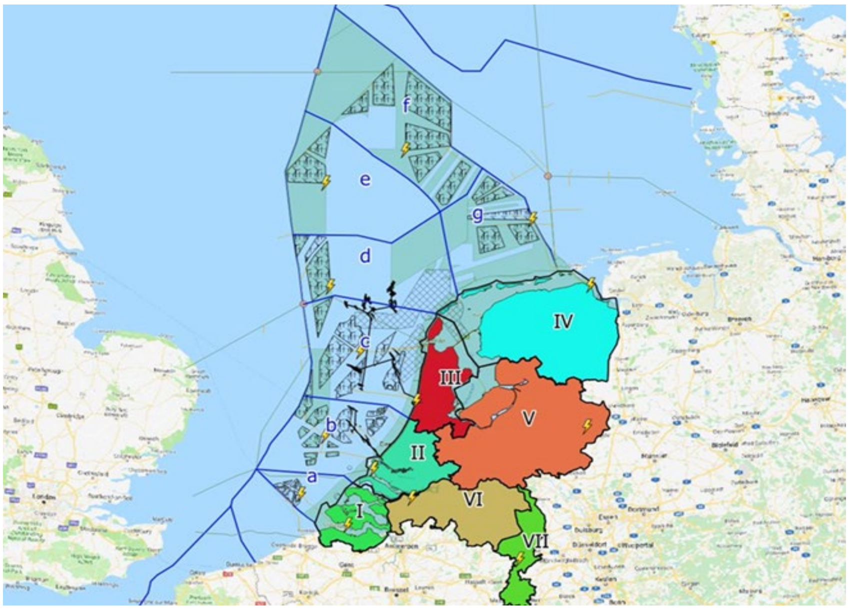


Figure 2.2: Onshore and offshore regions in het OPERA model

Large industry in the Netherlands is concentrated in five industrial clusters, see Table 2.1. These industrial clusters largely coincide with the regions in the model, with the exception of Noord-Brabant. The industry in West-Brabant around Bergen op Zoom is included in the Zeeland region and the industry in Moerdijk in the Zuid-Holland region. Other end-use sectors (built environment, agricultural sector, mobility) are also distributed across these regions.

Table 2.1: Industry clusters in the OPERA model

| Region | Indicated in OPERA | Industry cluster[5] |
|---|---|---|
| I | Zeeland | Zeeland-West Brabant |
| II | Zuid-Holland | Rotterdam-Moerdijk |
| III | Noord-Holland | Noordzeekanaal |
| IV | Noord-Nederland | Noord-Nederland |
| V | Midden-Nederland | - |
| VI | Noord-Brabant | - |
| VII | Limburg | Chemelot |

[5] As indicated in Cluster Energy Strategies (CES) 2022.

### Box 1 – OPERA and IESA-Opt

*TNO has two integrated national energy system models at its disposal, namely OPERA and IESA-Opt. The latter, developed by the ESTRAC program in collaboration with the University of Groningen, has also been used to study the use of nuclear energy in the Netherlands* (Fattahi, Van den Broek, Martínez-Gordón, Sánchez-Diéguez, & Faaij, 2022)*. Compared to OPERA, the IESA-Opt model (Integrated Energy System Analyses-Optimization) is more agile and user friendly. In contrast to OPERA, IESA-Opt uses a cost optimization over multiple years. In order to investigate to what extent outcomes can differ, calculations of the Dutch energy system were made for the same scenario (TRANSFORM from* (Scheepers, et al., 2024)*) with both models for this study. Since both models have different databases and topologies (i.e. how technologies are connected with each other), several assumptions had to be made in the alignment of the models, e.g. how the chemical sector is represented in the models. The results of the two models are largely comparable when calculating an energy system for the same scenario. The main differences are related to technological assumptions and topology, which can cause the cost-optimal transition path for the same scenario to differ, especially for* $CO_2$ *capture, use & storage (CCUS), and hydrogen. Both models deploy the same nuclear production capacity in 2050, with electricity production in IESA-Opt slightly lower than in OPERA. Overall, the model comparison shows that results from OPERA and IESA-Opt are largely consistent with each other and that IESA-Opt is flexible enough to also be used to answer national policy questions.*

### 2.1.2 COMPETES-TNO

COMPETES-TNO is a power system optimization and economic dispatch model that seeks to meet European power demand at minimum social costs (maximizing social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units, transmission interconnections and flexibility options across European countries and regions.

The COMPETES-TNO model covers all EU Member States and some non-EU countries – i.e., Norway, Switzerland, the UK and the Balkan countries (grouped into a single Balkan region) – including a representation of the cross-border power transmission capacities interconnecting these European countries and regions (see Figure 2.3). The model runs on an hourly basis, i.e., it optimizes the European power system over all 8760 hours per annum.

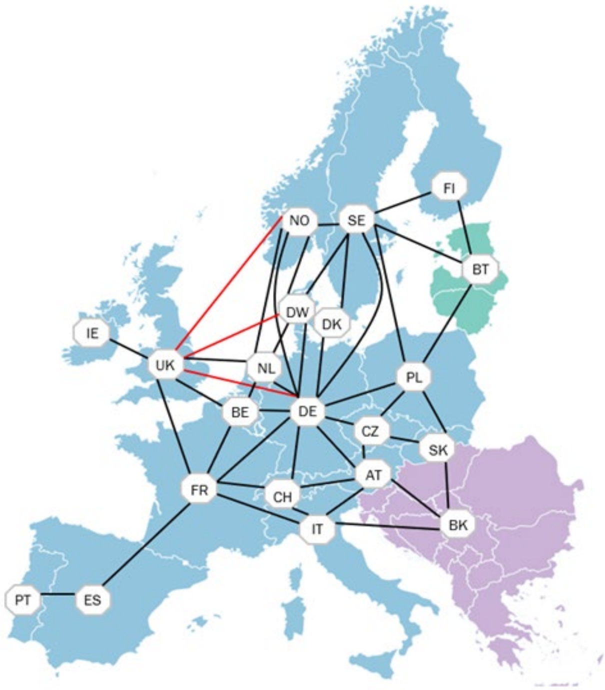


Figure 2.3: Countries represented in the COMPETES-TNO model

COMPETES-TNO consists of two major modules that can be used to perform hourly simulations for two types of purposes:

- *Transmission and generation capacity expansion module* to determine and analyse least-cost capacity expansion under perfect competition formulated as a linear program to optimize generation capacity additions in the system.
- *Unit commitment and economic dispatch module* to determine and analyse least-cost unit commitment (UC) and economic dispatch under perfect competition, formulated as a mixed-integer program considering flexibility and minimum load constraints and start-up costs of generation technologies and demand.

For each scenario year, the inputs of COMPETES-TNO include the following:

- Electricity demand across all European countries/regions, including conventional power demand and additional demand due to further sectoral electrification of the energy system by means of P2X technologies, such as Power-to-Heat (P2H), Power-to-Hydrogen (P2H2), or power-to-mobility (P2M).
- Power generation technologies, transmission interconnections and flexibility options, including their techno-economic characteristics.
- Hourly profiles of various electricity demand categories and renewable energy supply (RES) technologies (notably solar, wind and hydro), including the full load hours of these technologies.
- Assumed (policy-driven) installed capacities of renewable power generation technologies.
- Expected future fuel and $CO_2$ prices.
- Policy targets/restrictions, such as meeting specific renewable energy/greenhouse gas (GHG) targets or forbidding the use of certain technologies in certain countries (for instance, coal, nuclear or CCS).

For the purpose of the present study, which investigates the impact of nuclear investments on the power system of the Netherlands (and some surrounding countries), the first module (i.e. expansion model) is used. This module is chosen as it includes a wider range of flexibility options and modelling capabilities of the $H_2$ sector in future energy systems, compared to the UC module. OPERA also determines investments. Box 2 explains the differences between the two models.

These flexibility options include:

- Cross-border electricity and hydrogen trade
- Storage:
  - Hydro Pumped Storage (PS)
  - Compressed Air Energy Storage (CAES) and Advanced Adiabatic (AA-CAES)
  - Battery technology: by electric vehicles (EVs) and stationary batteries, Li-ion, lead-acid (PB), and vanadium redox battery (VRB)
  - Underground storage of hydrogen
- Demand response:
  - Power-to-mobility (P2M): with load-shifting and storage capabilities by vehicle-to-grid (V2G) and grid-to-vehicle (G2V) behaviour;
  - Power-to-heat (P2H): load shedding through industrial (hybrid) boilers and load shifting capabilities by household (all-electric) heat pumps;
  - Power-to-Hydrogen (P2H2): load shedding through electrolysers.
  - Industrial Load Shedding (ILS).

There are certain trade-offs when applying the investment module of COMPETES-TNO compared to the UC module. Firstly, there are less detailed operational constraints for some technologies, such as minimum load or ramping considerations in the investment module. In order to mitigate this limitation to some extent, an approximation on the operational behaviour for nuclear energy was implemented by including a minimum load constraint. Secondly, given that COMPETES-TNO is inherently a power market-based model the heat sector is not represented. This is particularly relevant for nuclear small modular reactors (SMRs), as they are capable of providing heat to industry due to their co-generation capabilities. In this case, the heat operation by SMRs is out of the scope in COMPETES-TNO. A third trade-off is the fact that the investment module does not include a physical electricity network representation (i.e. representation of Kirchhoff laws), hence the modelling of the electricity network lacks certain network constraints that hold in practise, where a flow-based network representation is applied. This creates more interconnection capacity for electricity trading, which can lead to import and export opportunities being overestimated.

The main outputs ('results') of COMPETES-TNO include:

- Investments and disinvestments ('decommissioning') in conventional and VRE power generation.
- Investments in interconnection capacities for internal European electricity and hydrogen trade.
- Investments in electrical and $H_2$ storage.
- Hourly allocation ('dispatch') of installed power generation and interconnection capacities, resulting in the hourly and annual power generation mix – including related $CO_2$ emissions and power trade flows – for each European country/region.
- Demand and supply of flexibility options.
- Electricity and hydrogen prices.
- Annual power system costs for each European country/region.

### 2.1.3 Model coupling OPERA and COMPETES-TNO

The OPERA model does not include foreign trade of electricity and hydrogen into its optimization process. To include the impact of this trade, exogenously determined trade profiles of electricity and hydrogen are fed into the model. These profiles come from the optimization process of COMPETES-TNO, together with the respective hourly electricity and hydrogen prices. This "coupling" approach between models is used also for the Climate and Energy Outlook for the Netherlands (KEV), as well as for previous studies with OPERA (Scheepers, et al., 2024).

#### Box 2 – Determining investments in nuclear energy

*Both OPERA and COMPETES-TNO calculate the investments in an optimal electricity production mix for a specific year that can meet the electricity demand under the boundary condition of a maximum amount of greenhouse gases. However, the outcome for investments in nuclear power plants in the Netherlands can be different: in OPERA, new nuclear power plants may be built, but may not appear in COMPETES-TNO. This can be explained by two fundamental differences between the two models:*

- *COMPETES-TNO and OPERA consider a different geographical area, respectively Europe and the Netherlands.*
- *In OPERA, all energy sectors are considered, while COMPETES-TNO focuses on the electricity production and related power-to-X sectors.*

*In COMPETES-TNO, the GHG emissions within the electricity sector are reduced by applying BECCS to electricity generation. BECCS in OPERA may not be applied to the electricity sector, but applied to processes that produce sustainable feedstocks and fuels, because this is more cost-efficient. Furthermore, in COMPETES-TNO, the application of BECCS in electricity production outside the Netherlands makes it possible to continue using natural gas for power generation in the Netherlands. In that case, $CO_2$ emissions in the Netherlands are offset by negative emissions abroad, see also . Most likely, differences in the role (scope, size, impact) of flexibility options between the two models also explain part of the differences in the optimal investment mix between these models.*

*In this study, the investments in electricity production are determined by the OPERA model and taken over in COMPETES-TNO via the model coupling. The investments in the other European countries are calculated by COMPETES-TNO.*
*Because the models each have a different scope and are intended for analyses from different perspectives, this study does not compare the results of both models.*

schematizes the coupling process steps.

Data harmonization was performed prior to the coupling process for key input parameters such as investment and operational costs (e.g. generation and storage technologies), VRE and biomass potentials, climate year VRE profiles, and fuel costs.

The coupling process is as follows: firstly, COMPETES-TNO starts optimizing the European power system in 2030 to 2050, (including the Netherlands) taking into account the assets already present from the previous year, and gives the resulting trade and price profiles to OPERA. This optimization is based on the Distributed Energy scenario from TYNDP-22, taking as input the electricity and hydrogen demands for the 2030-2050 period, as well as the initial installed capacities in 2030 as starting baseline and the transmission interconnection capacities (ENTSO-e & ENTSOG, 2022), including all existing NPP capacities. Notice that COMPETES-TNO does not invest in new NPP capacities, see Box 2. In step 2 OPERA runs on hourly basis (without regions) with the fed-in COMPETES-TNO results and optimizes the Netherlands energy system again for the period 2030-2050, for both ADAPT and TRANSFORM scenarios. In step 3 a second iteration takes place where COMPETES-TNO fixes the Netherlands results from OPERA in terms of electricity and hydrogen demand, as well as installed capacities of power generation in the Netherlands, including new NPP capacities, and flexible assets. In step 4 the resulting trade and price profiles are once again iterated in OPERA, finalizing with the regional optimization to obtain the final results.

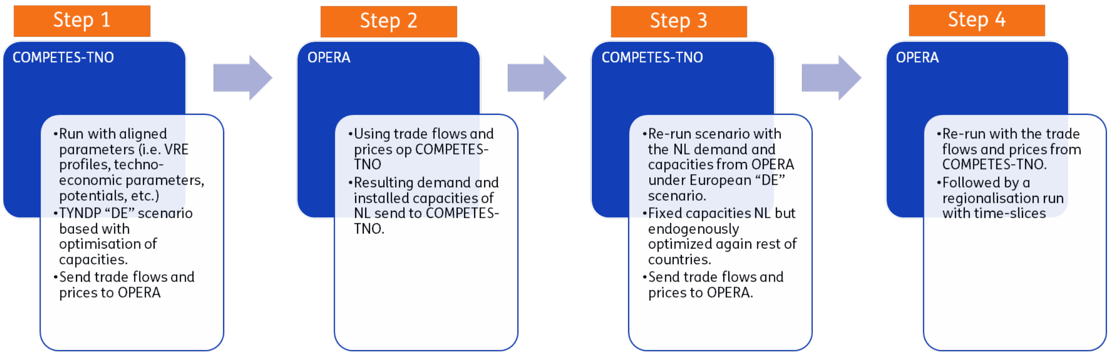


Figure 2.4: Soft linking OPERA with COMPETES-TNO for electricity and hydrogen trade between the Netherlands and neighbouring countries (flows and prices)

## Box 2 – Determining investments in nuclear energy

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*In this study, the investments in electricity production are determined by the OPERA model and taken over in COMPETES-TNO via the model coupling. The investments in the other European countries are calculated by COMPETES-TNO.*
*Because the models each have a different scope and are intended for analyses from different perspectives, this study does not compare the results of both models.*

### 2.1.4 Modelling the nuclear fuel cycle

This section, describes the analysis goals and, briefly, the numerical analysis methodology applied for the nuclear fuel cycle.

*Analysis goals*
The final goal is to provide a preliminary feasibility assessment for future Dutch nuclear fleet scenario. To do so, these scenarios have to be simulated in a fuel cycle analysis. In this fuel cycle analysis, key metrics associated with the demand for supply/resources, the production of specific materials and the demand for industry services is determined. A list of metrics analysed in this assessment is given below, categorized by fuel cycle stage:

- Front-end:
  - The demand for natural uranium, the primary resource used for the production of enriched uranium based fuels.
  - The demand for uranium enrichment, required to make reactor-grade enriched uranium.
  - The demand for fuel fabrication, based on the reactor fuel consumption levels.
  - The production of depleted uranium, originating from the tails of the enrichment process.

- Back-end:
  - The amount of spent fuel produced, and the associated demand for reprocessing if applicable.
  - The amount and form of high-level waste produced, and the associated demand for storage.

Each of these processes involves several intermediate or associated processes. For example, the production of natural uranium involves steps such as mining, purification, and chemical conversion. For the sake of clarity and simplicity, this analysis only considers the major encompassing processes listed above.

The simulation of the fuel cycle will provide quantitative metrics for the aforementioned themes, which are the main results of the analysis. Afterwards, these metrics will be placed in context based on known developments of the national and international nuclear ecosystem, and projections of the future development of several key markets. In doing so, the feasibility of the analysed scenarios can be assessed, and essential boundary conditions for realization are determined.

*Numerical analysis methodology*
The scenarios that are modelled in the analysis are assessed using a fuel cycle assessment code developed by NRG PALLAS. Within this code, each process or step in the cycle accepts a nuclide vector as input and/or creates a nuclide vector as output. For example, a nuclear reactor could take a nuclide vector of enriched uranium as input, and generates a spent fuel vector as output. This vector is passed to a subsequent step/process, except for the waste disposal process which is the final part of the cycle. A schematic of the modelled processes is given in Figure 2.5.

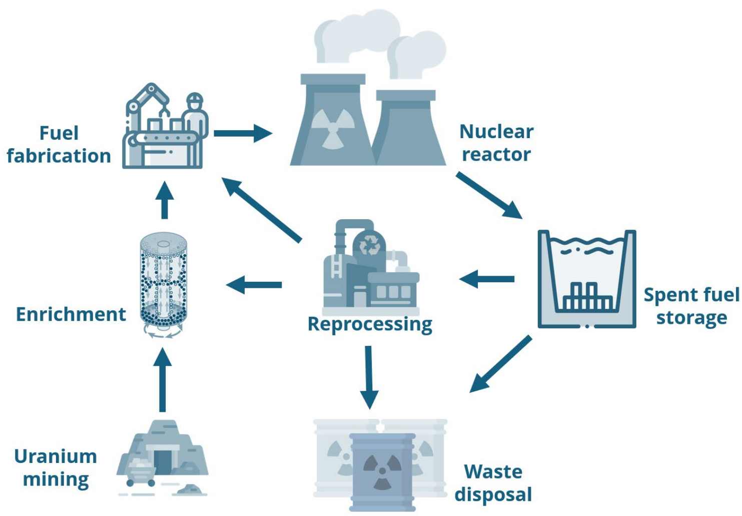



Figure 2.5: A schematic showing the steps in the nuclear fuel cycle that are considered in the analysis, and the relationship between them. Graphic created using icons from Flaticon.com.

There are several inputs that define any given nuclear fuel cycle:
- The nuclear reactor fleet: what types of reactors are operational at what point in time.
- The type of fuel the reactors make use of, characterized by their nuclide vectors.
- The specifications of the enrichment plant.
- Whether or not reprocessing is used (with vitrification of high-level waste), and if so, whether or not the reprocessed fissile material is reused.

All of these inputs define the magnitudes of the vectors, which are a function of time. In the simulation, these vectors are calculated and translated to the key metrics which have been mentioned above. The inputs span a large parameter space, meaning various combinations can be assessed. For this analysis two variants are considered (see Section 2.2.3) where many parameters are taken as fixed, typical values. The parameters used in the analyses listed are in paragraph 2.4.

# 2.2 Scenarios

For the present study existing scenarios were used. The scenarios for the transition to a climate-neutral Dutch energy system in 2050 are based on two visions on the future (storylines): ADAPT and TRANSFORM. The development of the demand for electricity and hydrogen in Europe is based on a scenario ('Distributed Energy') from the Ten Year Network Development Plan (TYNDP) of ENTSO-E and ENTSOG. The ADAPT and TRANSFORM scenarios are used for analyses with the OPERA model and the TYNDP scenario for analyses with the COMPETES-TNO model and the coupling with OPERA. Both scenarios are explained in more detail below.

## 2.2.1 ADAPT and TRANSFORM

Future transition paths for a sustainable Dutch energy system can be investigated using scenarios. Based on a coherent set of realistic assumptions and boundary conditions, scenarios describe the possible development of the energy system. Two scenarios drawn up

### Box 3 – Visions on the future (storylines)

*ADAPT*
- *Netherlands and EU will meet 2030 and 2050 GHG reduction targets.*
- *Society values the current lifestyle.*
- *EU countries have their own policies in achieving GHG reduction.*
- *Industrial production and economic structure remain basically the same.*
- *National and local government take the lead.*
- *Adapting and optimising the energy system and industrial processes.*
- *Planning for structural change post 2050.*
- *To abate $CO_2$ emissions, fossil fuels are expected to be utilised in combination with carbon capture and storage (CCS).*

*TRANSFORM*
- *The Netherlands and EU will meet 2030 and 2050 GHG reduction targets.*
- *Strong environmental awareness and sense of urgency in society.*
- *EU and Netherlands want to become an innovative powerhouse.*
- *Individual and collective action by civilians.*
- *Government has a stimulating and enabling role.*
- *Ambitious transformation of energy system, transition of energy intensive industry, resulting in lower industrial production and energy use, increase of service sector output.*
- *Reduction in other GHG intensive activities (such as animal husbandry and international travel).*
- *A limited use of $CO_2$ storage.*

by TNO were used for the present study: ADAPT and TRANSFORM (Scheepers, et al., 2024). These scenarios are based on different visions of the future for the Dutch energy system. In both visions, the aim is to reduce greenhouse gas emissions by 55% by 2030 and to achieve greenhouse gas neutrality by 2050. Population growth and the development of the overall Dutch economy are similar for both scenarios. The way in which the objectives are achieved is different. The two scenarios differ in particular in terms of intrinsic motivation and support for change among government, citizens, and companies (see Box 3).

### 2.2.2 Distributed Energy (TYDNP)

The associations of European Network of Transmission System Operators for Electricity and Gas (ENTSO-E & ENSTOG), elaborate every two years the Ten Year Network Development Plan (TYNDP). The TYNDP is an assessment of the European energy infrastructure entailing development of electricity and gas transmission projects and storage facilities. As part of the assessment, European network operators develop future scenarios with different assumptions on the future electricity and gas demand and the installed capacities of different technologies per EU-27 member state. These scenarios are:

- **National Trends**: this scenario considers the current national energy and climate policies of the different European countries, covering the time horizon up to 2040.
- **Global Ambition**: follows a storyline where the carbon reduction targets of EU-27 carbon neutrality by 2050 and at least 55% emission reduction by 2030 is achieved. The main pathways to achieve this are based on a centralized approach, with focus on global energy trade to achieve decarbonization.
- **Distributed Energy**: with same carbon targets as Global Ambition, the storyline of this scenario is driven by a decentralised approach, based on citizen leadership.

Considering the necessary scenario inputs for the power market model (initial installed capacities in 2030 and the hydrogen and electricity demand for the period 2030-2050), National Trends is not suitable, due to the study' time horizon of 2040 and 2050, where nuclear capacity would play a role in the energy system for the Netherlands. The GE scenario is also not suitable because global energy trade does not fit in with the ADAPT and TRANSFORM scenarios

For the purpose of the present study, the Distributed Energy (DE) scenario from the TYNDP-22 edition (ENTSO-e & ENTSOG, 2022) was chosen to model the European power system in COMPETES-TNO. A comparative analysis between the demand projections of the European scenarios for the Netherlands and the national ADAPT and TRANSFORM storylines showed that DE is the most suitable scenario in terms of electricity and hydrogen assumptions. For the detailed quantification of the scenario assumptions for the DE scenario in COMPETES-TNO, see Section 2.1.2.

Additionally, during the elaboration of this report, the latest edition of the TYNDP-24 scenarios was published. The updated DE scenario is assessed as part of a "What if" analysis, named "TYNDP24" (ENTSO-e & ENTSOG, 2024), to gain insight into the effects of changes in electricity and hydrogen demand in European countries.

### 2.2.3 Variants nuclear fuel cycle

For the analysis of the nuclear fuel cycle, two variants are analysed for the two base scenarios, ADAPT and TRANSFORM:

- **Variant A:** all reactors make use of enriched natural uranium (UOX) fuel. Potentially, the spent fuel could be reprocessed and the high-level waste vitrified, but the reprocessed materials are not re-used.
- **Variant B:** all reactors make use of a combination of UOX and MOX (Mixed Oxide Fuel). MOX is a mixture of depleted uranium and reprocessed plutonium. The ratio between UOX and MOX is chosen as such that all plutonium that results from reprocessing UOX is re-used in MOX. MOX will have a share of around 16% in the reactor core, see Appendix F. All spent fuel is reprocessed, and high-level waste is vitrified.

Further explanation on the calculation of mass flows and the balancing of UOX and MOX is provided in Appendix F.

In the nuclear fuel cycle analysis for ADAPT and TRANSFORM, the Borssele reactor is not taken into account explicitly. To obtain a more complete picture, a Business As Usual (BAU) scenario, labelled BORSSELE, has been added for comparison with the current situation. Currently, the Borssele reactor makes use of a combination of MOX, and UOX using enriched natural uranium or, re-enriched depleted uranium, compensated enriched reprocessed uranium or down blended military-grade uranium (the latter three being not considered in this analysis). The most realistic choice is to assume the Borssele plant will maintain its current operational approach till its end of life. Therefore, no simulation using the model variants is performed for the BORSSELE scenario. Instead, key metric based on reported actual data, and derivations made for this, is used for the BORSSELE scenario.

Table 2.2 summarizes the scenarios and variants applied to analyse the nuclear fuel cycle.

Table 2.2: Scenarios and variants for the nuclear fuel cycle analyses

| | BORSSELE | ADAPT (Baseline) | TRANSFORM (Baseline) |
|---|---|---|---|
| Variant A | | √ | √ |
| Variant B | | √ | √ |
| Existing fuel strategy | √ | | |

## 2.3 Parameters energy system

This section outlines the input parameters used for the energy models OPERA and COMPETES-TNO:

- Demand parameters
- Commodity prices
- Boundary conditions
- Techno-economic parameters of NPPs
- Techno-economic parameters for other technologies

Note that the cost parameters (energy prices, techno-economic parameters) are expressed in 2015 euros. In 2024 euros, costs and prices are approximately 30% higher.

### 2.3.1 Demand parameters

**Energy demand for the Netherlands (OPERA)**
An important driver for the model analysis is the future energy demand that the energy system must meet. The energy demand for various end-user sectors is determined by the OPERA model based on the size of activities (i.e. service demand), such as the number of homes, the floor area offices and commercial buildings, passenger and freight kilometres and production of industrial products. This information is supplemented with energy demand data for a number of other activities. The input parameters used with regard to energy demand are presented in Appendix A and are derived from projections of the Climate and Energy Outlook 2022 (PBL, 2022). The applied demand input parameters assume an equal demographic development of the Dutch population in both scenarios. Also, for economic development the same annual GDP growth rate of 1.7% per year is assumed for both scenarios. To reflect the assumed behavioural changes in the TRANSFORM scenario, a decrease in mobility demand, a lower industrial production in most industrial subsectors and a lower agriculture production are assumed compared to ADAPT. To compensate for lower economic activity in industrial and agriculture sectors, TRANSFORM assumes that the service sector will become larger than in the ADAPT scenario.

**Energy demand for Europe (COMPETES-TNO)**
For COMPETES-TNO, the energy demand comprises electricity and hydrogen. The input parameters for demand are based on the TYNDP-22 Distributed Energy (DE) scenario (ENTSO-e & ENTSOG, 2022). The electricity demand modelled in COMPETES-TNO is classified into:

- Conventional power demand: it corresponds to all inflexible electricity consumption from all sectors. The profile of this demand is based on the historical demand profile from the weather year 2015.
- Flexible power demand: includes the demand of Power-to-X technologies as a result of the future electrification of the energy system.

This flexible demand is sub-divided into:

- *Power-to-Heat-i* : comprised by steam and heat processes by industry. This demand is assumed to be flexible through the utilization of hybrid (electricity/gas) boilers. The final power demand will rely on the relative prices of natural gas (exogenous parameter) and electricity (calculated by the mode)l.
- *Power-to-heat-h*: consists of the space and water heating from all-electric heat pumps of the residential sector, and it is considered to be flexible through demand shifting capabilities.
- *Power-to-mobility*: represents the electricity demand by electric passenger vehicles (EVs), and it includes both vehicle-to-grid (V2G) and grid-to-vehicle (G2V), acting as demand shifting and storage technology.
- *Power-to-hydrogen*: represents specifically the demand for electrolyser-type technologies. This demand profile is flexible and optimised endogenously by the model according to hourly electricity prices, i.e. producing more hydrogen when electricity prices are low, and shedding or reducing production when prices are high.

The electricity and hydrogen demand for the Netherlands in COMPETES-TNO are based on the OPERA results, see 3.1.4 and 3.1.5. For other countries, the exogenously defined electricity demand for surrounding countries and hydrogen demand from the TYNDP-22 DE scenario used as input for the modelling is reported in Appendix B. This exogenously demand comprises “inflexible” demand and “flexible” demand from EVs and heat pumps.

Furthermore, the final demand includes endogenously electricity demand from P2H2 and P2Heat operation and therefore varies per scenario simulation.

### 2.3.2 Commodity prices

For fuels that are supplied from outside the energy system OPERA and COMPETES-TNO use the same prices from several price projections. The prices for fossil fuels are based on advice from the European Commission (European Commission, 2022). Prices for different types of biomass have been obtained from the Climate and Energy Outlook 2022 (Klimaat en Energieverkenning, 2022). Prices used for biofuels (biodiesel and bioethanol) are assumed to be constant over the period considered and correspond to data from the AdvanceFuel project[6]. Prices for green ammonia and e-methanol are derived from a HyDelta study (Hajonides van der Meuelen, Scaric, Tyraskis, & Verstraten, 2022). Fuel prices used in the scenarios are shown in Appendix C. The prices of hydrogen and electricity are determined endogenously by both models.

### 2.3.3 Boundary conditions

Two types of boundary conditions are imposed to the scenarios:

- Boundary conditions regarding the reduction of greenhouse gas emissions and sustainable carbon use (see Table 2.3).
  - A GHG reduction target of 55% applies for 2030 and by 2050 no net greenhouse gas emissions may be emitted (Dutch Government, 2023), i.e. the NL energy system is GHG neutral by 2050.
  - The following GHG reduction targets apply for intermediate years: 70% for 2035, 80% for 2040 and 90% for 2045.
  - In TRANSFORM the GHG emissions of the Dutch ETS sector are zero in 2040 and following years as a result of the tightening of allowances proposed by the European Commission (European Commission, 2023). For ADAPT no specific target is applied for the ETS sector.
  - GHG emissions from international aviation and shipping fall outside the Dutch reduction target. The extent to which sustainable fuels are part of bunker fuels in the Netherlands is influenced by GHG reduction measures for these sectors. TRANSFORM assumes that GHG emissions in 2050 for international aviation and shipping are reduced by 100%, with a 2040 reduction target of 53% for international aviation and 70% for maritime shipping. ADAPT assumes a less ambitious GHG reduction: 50% in 2050 and a reduction target in 2040 of 30% for international aviation and 45% for maritime shipping.
  - To make carbon in feedstocks more sustainable, a target for the share of sustainable carbon (i.e. biogenic or atmospheric carbon) is imposed. For 2030 this share is 5% and it will increase in TRANSFORM to 80% in 2050. For ADAPT, the target is abandoned after 2030.
- Restrictions on the use of technology (See Table 2.4)
  - Deployment restrictions apply for wind onshore, wind offshore, solar PV and geothermal energy. These limitations relate to when technology becomes available, the growth of the technology that seems realistic, and physical or policy limitations.
  - In accordance with current policy, $CO_2$ storage can be used to a limited extent in 2030 in both the ADAPT and the TRANSFORM scenario. An increase in $CO_2$ storage is possible in the ADAPT scenario, but in the TRANSFORM scenario only to enable

[6] See: http://www.advancefuel.eu/

negative emissions to compensate for emissions of activities that are difficult to reduce (e.g. emissions from non-$CO_2$ greenhouse gases, non-energy $CO_2$ emissions and GHG emissions of land use).
- The amount of domestically available biomass is insufficient to meet the demand for biofuels and bio-based feedstocks. Therefore, in addition to the domestic available biomass, biomass import is assumed to a maximum. This maximum is based on various studies potential estimates, see (Scheepers, et al., 2024).
- From 2030, coal-fired power plants can no longer be used (Ministry of EZK, 2019).

The following assumptions have been made for the use of NPPs in both scenarios:

- The existing Borssele NPP will be in operation until 2043. A long term operation (LTO) of 10 years (i.e. lifetime extended to 70 years) is proposed and under investigation by the Dutch government.
- The Dutch government intends to make the realization of new NPPs possible. In addition to the previously announced expansion of the nuclear capacity with two large NPPs, the Dutch government wants to realize two additional NPPs in the Netherlands (Dutch Government, 2024). It is assumed that the first large NPP (1500 $MW_e$) can be operational in 2035 and that every five years thereafter an additional new NPP with a similar size can be operational, resulting in four large NPPs in 2050 with a combined capacity of 6000 $MW_e$. For the present study, these capacities are considered as a maximum.
- In addition to the large NPPs, it is assumed that small nuclear power plants (SMRs) can be built with cogeneration of electricity and heat. It is assumed that SMRs will become commercially available after 2030, with the first ones operational in the Netherlands by 2040 (Scheepers, Haas, Roelofs, Jeeninga, & Gerdes, 2020). The rollout of SMRs is assumed to reach a maximum capacity of 450 $MW_e$ in 2040, gradually increasing to a maximum total capacity of 2100 $MW_e$ in 2050 (a construction rate of three to four 150 $MW_e$ SMRs every five years).

Table 2.3: GHG reduction targets

| | Unit | ADAPT | | | | | TRANSFORM | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2030 | 2035 | 2040 | 2045 | 2050 | 2030 | 2035 | 2040 | 2045 | 2050 |
| GHG reduction target (wrt 1990) | % | 55% [a] | 70% | 80% | 90% | GHG neutral [a] | 55% [a] | 70% | 80% | 90% | GHG neutral [a] |
| GHG emissions international transport | Mt $CO_2eq$ | | | | | | | | | | |
| Aviation (% reduction wrt 2005) | | 10.7 [b] | 9.4 | 8.1 | 6.2 | 5.5 (50%) | 9.2 [b] | 6.9 | 4.6 | 2.3 | 0 (100%) |
| Shipping (% reduction wrt 2008) | | 34.4 [b] | 32.5 | 30.5 | 28.6 | 26.7 (50%) | 31.2 [b] | 23.4 | 15.6 | 7.8 | 0 (100%) |
| Circular carbon target for production of chemicals | % | 5% [c] | 0% | 0% | 0% | 0% | 5% [c] | 20% | 40% | 60% | 80% |

[a] Climate Act 2023

[b] Based on a 6% share of renewable and low-carbon fuels (European Commission, 2023), (European Commission, 2021)

[c] This non-fossil criterium is added in line with policy described in (Ministerie van Infrastructuur en Waterstaat, 2023)

Table 2.4: Potentials for technology options

| | Unit | ADAPT | | | | | TRANSFORM | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2030 | 2035 | 2040 | 2045 | 2050 | 2030 | 2035 | 2040 | 2045 | 2050 |
| Wind energy potential | GW | | | | | | | | | | |
| Onshore | | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 8.9 | 10 | 11 | 12 |
| Offshore | | 16[a] | 26 | 36 | 38 | 40 | 16[a] | 30.5 | 45 | 57.5 | 70[c] |
| Solar energy potential (PV) | GW | 36.6[b] | 52.7 | 68.6 | 88.8 | 109.0 | 42.9[b] | 64.7 | 83.6 | 107.7 | 132.1 |
| Nuclear capacity | GW | | | | | | | | | | |
| Borssele[d] | | 0.5 | 0.5 | 0.5 | | | 0.5 | 0.5 | 0.5 | | |
| New nuclear power potential | | | | | | | | | | | |
| Large Gen III | | | 1.5 | 3 | 4.5 | 6 | | 1.5 | 3 | 4.5 | 6 |
| SMR | | | | 0.45 | 0.9 | 2.1 | | | 0.45 | 0.9 | 2.1 |
| $CO_2$ storage potential | Mt | | | | | | | | | | |
| Industry | | 9.7[e] | 24 | 35 | 40[f] | 40[f] | 9.7[e] | 12.7 | 12.7 | 12.7 | 15[g] |
| Power generation | | 3[e] | | | | | 3[e] | | | | |
| Geothermal potential[h] | PJ | 50 | 88 | 125 | 163 | 200 | 50 | 88 | 125 | 163 | 200 |
| Biomass potential | PJ | | | | | | | | | | |
| Domestic | | 164 | 183 | 202 | 221 | 241 | 164 | 175 | 186 | 198 | 209 |
| Import[i] | | 83.4 | 225 | 366 | 508 | 650 | 83.4 | 225 | 366 | 508 | 650 |

[a] 6 GW additional to Climate agreement.
[b] Monitor RES 1.0 (PBL, 2021).
[c] 70 GW wind offshore is based on (Matthijsen, Dammers, & Elzinga, 2018). An other study by Taminiau and Van der Zwaan calculates a physical potential up to 99 GW (Taminiau & van der Zwaan, 2022).
[d] For Borssele a long term operation (LTO) of 10 years is assumed after 2033.
[e] Climate agreement, 2.5 Mt additional for industry (2022). However, the subsidy ceiling in the SDE++ expired in 2023, i.e., de facto there is no maximum.
[f] The potential is derived from the total available storage capacity of 1,600 to 1,700 Mt in the Dutch part of the North Sea (Joint Fact Finding $CO_2$-afvang en -opslag, Klimaattafel, 2018).
[g] Potential needed for sufficient negative emissions.
[h] Based on (Platform Geothermie, 2018).
[i] TNO own assessment based on the recent DG RTD study (EC, 2024). The assessment approach can be found in (Scheepers, et al., 2024).

## 2.3.4 Nuclear techno-economic parameters

**Economic parameters**

For the representation of nuclear energy in the models of the present study, there are two key components: economic and technical parameters. They are key from the perspective of investment decisions and as well as for the accurate representation of the operation of this type of technology. For the purpose of the present study, we consider for new NPP investments two different types, both water cooled light water reactors of generation III[7]:

- Large NPPs, with installed capacities above 1000 $MW_e$, providing only electricity output.
- Small Modular Reactors (SMRs), usually with capacities of less than 500 $MW_e$ installed. SMRs are capable to produce both electricity and heat. Within this nuclear category, we differentiate SMRs for:
  - producing electricity in combination with low pressure steam heat supply (heat output between 100-200 °C).
  - producing electricity in combination with high pressure steam (heat output between 200-400 °C).

Based on a literature review of the main economic parameters of large NPPs and SMRs (see Appendix D), this study uses the parameters shown in Table 2.5.

Table 2.5: Cost parameters assumptions for the two nuclear reactor types used in this study (expressed in € 2015)

| | Large NPP | SMR |
|---|---|---|
| Overnight Capital Cost[8] (€/kW) | 2030: 5811<br>2040: 5404<br>2050: 4998 | 2030: 6776<br>2040: 6301<br>2050: 5827 |
| Fixed O&M (incl. costs for plant decommissioning) (€/kW) | 108 | 124 |
| Variable O&M (incl. front-end and back-end costs[9]) (€/MWh) | 19 | 20 |

**Technical parameters**

Regarding the technical parameters, they refer mainly to electric and heat efficiencies, rated power and availability factors.

*Large NPPs*

In a future system with a high penetration of VRE, NPPs' operation would be required to be flexible (i.e. load following). The capability of nuclear to perform flexibly is currently an important research question from the technical, as well as economic point of view. There are certain limitations for a NPP on the amount of times it can switch on and off completely and how much it can be adjusted, as well as the type of controlling mechanisms to adjust the nuclear load. A market analysis within the Dutch context was carried out to find which type of reactors would be most likely be built in the coming two decades in the Netherlands. From this analysis, a generic large NPP technical design was defined. The parameters are shown in Table 2.6. The load following range is used in both OPERA and COMPETES-TNO. The

[7] Generation III reactors are further developed second generation reactors, such as those built in the 1970s and 1980s.
[8] The reduction of costs towards 2050 are based on an assumed 14% cost reduction, i.e. the difference between first-of-a-kind (FOAK) and number-of-a-kind (NOAK) (Gamboa Palacios & Jansen, 2018).
[9] Front-end costs are the costs of nuclear fuel (mining, milling, conversion, enrichment, and fuel fabrication) and back-end costs are the costs of spent fuel treatment (reprocessing and recycling) and nuclear waste disposal (temporary storage, geological disposal).

limitation on the number of cycles is not explicitly modelled. Instead, an assessment of the model results is performed. Note that the OPERA model does not distinguish discrete capacities, but determines an optimal capacity for a technology in the total system.

Table 2.6: Generic large NPP definition

| Parameter | Description | Value |
|---|---|---|
| Thermal power | Unit gross thermal power generation. Typical minimum power generation is in the order of 20% of the maximum rated thermal output, although dependent on the irradiation cycle. | 4300 ($MW_{th}$) |
| Electric power | Unit gross electric power generation | 1500 ($MW_e$) |
| Electric efficiency | Overall factor from which heat can be converted in electricity. | 35 (%) |
| Availability factor | Amount of time available to operate | 95 (%/year) |
| Ramp rate | The power variation for power ramps (up and down) per unit of time. | 5 (% P/min) |
| Load following range | Manoeuvring capabilities | 20-100 (%) |
| Cycle count limit | Number of load variations from full power to minimum load to back to full power in an amount of time. | Maximum: 2 variations/day; 5 per week; 200 per year |

*Small Modular Reactors*
The electrical capacity of an SMR can vary between 50 and 500 $MW_e$. For the present study two general SMR are defined with parameters shown in Table 2.7, in addition to the parameters for large NPPs, shown in Table 2.6 (however, note that the OPERA model does not distinguish discrete capacities). As already mentioned above, SMRs are intended to supply steam to industrial processes preferably at 150 or 300 degrees Celsius. Although in practice SMRs will be able to supply both heat and electricity at the same time, in OPERA the SMR is limited to either the heat supply mode or the electricity supply mode, due to the linear programming characteristic of the model.

Table 2.7: Generic SMR definition

| Parameter | Value |
|---|---|
| Thermal power | 430 (MW) |
| Maximum electric output | 150 ($MW_e$) |
| Maximum heat output | 344 ($MW_{th}$) |
| $T_{heat}$ | 150 (°C)<br>300 (°C) |

## 2.3.5 Techno-economic parameters other technologies

OPERA calculates a cost-optimal energy system for which the model can choose from approximately 600 technology options. Technology options include techniques for production, conversion, transport and use of energy, techniques for capturing, transporting, and storing $CO_2$ and other $CO_2$ sequestration technologies, and energy saving options. The techno-economic data for these options are retrieved from a database containing current data and projections for parameter values in 2030 and 2050. A full list of this data can be found in (Scheepers, et al., 2024). In addition, a number of techniques are described in data sheets[10]. The performance and cost parameters for 2030 and 2050 take into account technology learning, i.e. cost reduction and performance improvement as a result of R&D and technology deployment. For technologies with learning potential for which the learning rate is unknown, an investment cost reduction of 20% is assumed between 2030 and 2050. It is assumed that the technology development and the costs of the technology are the same in both scenarios.

Apart from the parameters for large NPPs and SMRs some adjustments were made for the present study compared to (Scheepers, et al., 2024):

- Wind profiles have been updated. Like COMPETES, OPERA uses now CorRES profiles (Koivisto, 2022)
- Solar PV profiles have been updated, using JRC PVGIS[11]
- Costs parameters for Direct Air Capture (DAC) technologies have been updated.
- The option 'Aromatics production via biomass' has been updated for both costs and the inputs/outputs. This option no longer has an output for captured $CO_2$.
- Bio energy carbon capture & storage (BECCS) for electricity production has been updated using data from COMPETES-TNO.

# 2.4 Parameters nuclear fuel cycle

## 2.4.1 Enrichment

For the calculation of mass flows, natural uranium ('feed') is assumed to have an enrichment of 0.72%, and depleted uranium ('tails') has an enrichment of 0.25%. Given the enrichment required for the fuel ('product'), these parameters are used to calculate the required amount of natural uranium, as well as the required amount of SWUs (Separative Work Unit). SWU is a measure of the work that needs to be done for the enrichment of uranium. The higher the enrichment in the 'product', the lower the enrichment in the 'tails' will be (with the same amount of natural uranium) (NEA, 2022). In other words, the greater the demand for enriched uranium, the more SWUs are needed.

## 2.4.2 Reprocessing

In a reprocessing plant, spent fuel is chemically dissolved and separated into three main constituents: uranium and plutonium on the one hand, and other minor actinides and fission products on the other hand. The fission products and minor actinides (except plutonium), which make up the majority of the high-level waste, are subsequently vitrified. Vitrification is a process in which the waste is mixed into a molten glass, after which this is stored in a waste canister. In this analysis, only reprocessed plutonium is re-used as a feed material for MOX fuel. Due to the efficiency of the reprocessing scheme, a small amount of uranium and plutonium (around 0.3% of the uranium and 0.2% of the plutonium) also ends up in the vitrified waste (Gruppelaar, Kloosterman, & Konings, 1998).

The vitrified waste is stored in CSD-V (Colis Standard de Déchets Vitrifiés) waste containers, these are then stored in the storage facility. The amount of CSD-Vs produced depends on the composition of the high-level waste and the container limits, which are given in Table 2.8.

[10] See: https://energy.nl/datasheets/
[11] See: https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en

Table 2.8: Maximum limits for a CSD-V container (Verhoef, et al., 2016).

| Limit per container | Value |
|---|---|
| Heat production (W) | 2000 |
| Alpha fluence [12] (Bq·s) | 4E+24 |
| Mass U (g) | 4500 |
| Mass Pu (g) | 110 |
| Activity Cs-137 (TBq) | 6600 |
| Activity Sr-90 (TBq) | 4625 |

In addition to the vitrified waste, a second waste stream is created, namely the compacted waste, which is also stored in packages (CSD-C containers, which have the same dimensions as CSD-V containers). These packages are filled with the structural materials of the fuel (such as cladding) and 'technological waste' (from the reprocessing process). In terms of mass, the structural elements from fuel assemblies constitute around 90% of the waste. In PWR (Pressurized Water Reactor) fuel, structural materials account for around 50 kg/tHM (tHM – tonne of heavy metal), and a typical CSD-C is filled with about 500 kg of mass. This means that around 0.1 CSD-C per tHM are produced. Most of the activity and heat production comes from activation products in the structural materials, with Co-60 making the dominant contribution. Typically, CSD-Cs will produce about 40 W of heat at production (and thus are stored in the 'cold side' of the HABOG [13], the high-level waste storage facility at the Dutch waste processing and storage site COVRA), and cool down relatively quickly due to the half-life of Co-60 (Verhoef, et al., 2016). Before SNF (Spent Nuclear Fuel) can be reprocessed, it has to cool down. During this period, the SNF is often stored in a basin near the reactor where it was produced. The longer the cooling takes, the lower the alpha activity and heat of decay in the waste will be, and therefore the more waste per package can be processed. However, the cooling period also results in a lower fraction of (fissile) Pu-241 in the fuel to be reprocessed, due to decay. A cooling period of 5 years has been chosen in this analysis, but in reality this may be closer to 10 years. Assuming a short cooling period is a moderately conservative choice, as a larger amount of reprocessed waste packages will arise from the same amount of spent fuel. Additionally, this assumes that the generation of vitrified waste containers starts earlier, meaning storage capacity needs to be available sooner.

## 2.4.3 Fuel properties

In the analysis, two types of nuclear reactors are considered: the LR (Large Reactor) and the SMR (Small Modular Reactor). These are both water-cooled reactors (LWRs) using low-enriched uranium dioxide (UOX, $UO_2$) or MOX (mixed-oxide, (Pu,$UO_2$) as fuel. Nuclear reactor fuel is typically characterised by its burnup, which is a metric of the amount of energy generated by unit of mass. Different burnup values for the LR and SMR have been chosen. Because of the smaller core of the SMR, it is expected that a larger amount of neutron 'leakage' occurs, which means that a lower burn-up will be achieved using fuel with the same enrichment. The values chosen are 45 GWd/tHM (gigawatt-days per tonne of heavy metal) for SMRs and 55 GWd/tHM for LRs. The enrichment (%U-235) of both fuels has been

[12] This is the alpha activity of Am-241, Am-243 and Cm-244 integrated over 10,000 years for a package with a capacity of 400 kilos of glass.
[13] Hoogradioactief Afval Behandelings- en OpslagGebouw

chosen as 4.9%, at the conventional limit for enrichment in commercial nuclear reactors (typically ≤4.95%). In the case of MOX fuel, a total plutonium mass fraction of 8.4% has been chosen, of which 64.1% consists of fissile plutonium, which roughly corresponds to what is used in the Borssele NPP (EPZ, 2010, p. 27). The spent fuel vectors have been sourced from a database of Monte-Carlo simulation based calculations (Elter, Zsolt et al., 2020). Table 2.9 shows the enrichment for fresh fuel for different fuel types, and the composition of spent fuel for a selection of key nuclides.

Table 2.9: Mass distribution of elements in spent UOX fuel, for the different reactors. Results by the Borssele nuclear powerplant operator EPZ for has been added for comparison. For the LR and SMR, the enrichment is 4.9%. In the Borssele reactor, the fuel is enriched to 4.4% (EPZ, 2010)

| Type of nuclear fuel | Enrichment [%] | Burnup [GWd/tHM] | Spent U [kg/tHM] | Spent Pu [kg/tHM] | Spent MA [kg/tHM] | Spent Cs+Sr [kg/tHM] |
|---|---|---|---|---|---|---|
| LR (Elter, Zsolt et al., 2020) | 4.9 | 55 | 927 | 14.5 | 1.48 | 3.95 |
| SMR (Elter, Zsolt et al., 2020) | 4.9 | 45 | 939 | 13.0 | 1.08 | 3.28 |
| Borssele ENU (EPZ, 2010) | 4.4 | 53 | 944 | 10.8 | 0.54 | 3.86 |
| Borssele MOX-40% (EPZ, 2010) | 4.4 | 53 | 915 | 53.5 | 4.40 | 3.32 |

The comparison with the existing Borssele NPP shows that there is relatively more plutonium and MA (Minor Actinides) in the simulated model fuel. From this comparison it can be concluded that the inventory of nuclides used in the spent fuel is a conservative but acceptable choice, given the higher fraction of plutonium and actinides (especially americium). The complete inventory of the spent fuel is provided in Appendix E.

### 2.4.4 Waste storage

There are two main HLW (High Level Waste) storage routes assessed in this analysis. In the first route, no reprocessing takes place. The spent nuclear fuel (SNF) is directly stored after intermediate cooling. The spent fuel assemblies are transferred to a storage container, and these containers will be placed in a storage facility. The second route, with reprocessing, involves separating the HLW from the actinides in the spent fuel. The actinides are assumed to remain in the fuel cycle (i.e. stored for future usage), and will not be disposed. The HLW is vitrified, and the containers containing this waste will be disposed of.

For the temporary and permanent storage of radioactive waste (HLW or SNF), depending on the chosen fuel strategy, different containers can be used for the storage of complete fuel assemblies. Table 2.10 gives an overview of different waste containers. In this analysis, SNF is assumed to stay in dry storage using CASTOR containers, and vitrified waste will be stored in CSD-V containers. Final disposal is out of scope for this analysis, so solutions built for purpose are not considered (e.g. CSD-V + overpack).

Table 2.10: Dimensions for different ways of storing high level radioactive materials.

| Container type | Length [m] | Diameter [m] | PWR assemblies | Volume container [$m^3$] | Density [$tHM/m^3$] | Source |
|---|---|---|---|---|---|---|
| PWR assembly (wet storage) | 4.00 | 0.22 | 1 | 0.18* | 2.70 | (Sanders, 2002) |
| CASTOR (dry storage) | 5.94 | 2.44 | 19 | 27.78 | 0.34 | (GNS, 2023) |
| KBS Canister (direct final disposal) | 4.84 | 1.05 | 4 | 4.19 | 0.48 | (Wu, Hexi, & Yang, 2014) |
| CSD-V (vitrified waste) | 1.34 | 0.43 | - | 0.19 | - | (Vernaz & Bonin, 2008) |
| CSD-V + overpack | 1.59 | 0.57 | - | 0.41 | - | (B., 2020) |

*In this case, it is the volume of a fuel assembly.

Besides high-level waste, new nuclear installations also produce low and intermediate level operational waste (LMRA), and decommissioning waste at end-of-life. These types of waste are not addressed in this analysis. High-level waste is responsible for the vast majority of the total activity of all waste, but only responsible for a fraction of the volume. Conversely, depleted uranium is responsible for the largest amount of volume to be stored. However, storing this material is easier and requires little shielding and other safety precautions, unlike HLW.

It should be noted that the volumes of waste that are to be stored have been assessed independently from COVRA. The results presented in this work are not representative of COVRA's own projections or views, and are only valid within the scope of the scenarios assessed using the assumptions and methodology mentioned in this work.

## 2.4.5 Deployment of capacity

The nuclear fuel cycle analyses are based on the capacities of the existing Borssele NPP and new NPPs to be built (Large NPPs and SMRs), as shown in Table 2.4. The amount of nuclear fuel will result from the use of the NPPs (i.e. number of full load hours) which will be calculated with the OPERA model for ADAPT and TRANSFORM, see Section 3.1.3. Although the time-frame of the scenario analysis from which these values of newly installed capacity are retrieved ends in 2050, the reactors are assumed to remain operational beyond that point till the end of their technical lifetime. It is assumed that the existing Borssele NPP closes in 2043. For or all new build reactors, it is assumed the technical lifetime is 60 years. As such, the simulation of the nuclear fuel cycle will run till the final processes associated with the last reactor shutting down have ended.

The research reactors (HFR (Petten), HOR (Delft) and in the future PALLAS (Petten) have not been taken into account in this analysis. This choice was made because, given their relatively limited combined thermal power (<100 $MW_{th}$), their impact on the analysed scenarios is minimal, especially in the context of 8 $GW_e$ of additional new NPP capacity being installed.

# 3 Nuclear energy in the energy system

This chapter presents results of analyses with the integrated energy system model OPERA on the role of new NPPs in the future Dutch energy system. This role is analysed by comparing ADAPT and TRANSFORM scenarios with new NPPs (both large scale and SMRs) with the same scenarios in which these new NPPs are not allowed. The results of this comparison are discussed in Section 3.1. The differences in system costs of both scenarios with and without nuclear energy are discussed in Section 3.1.7. Regarding installed capacity for nuclear, wind and solar energy, and system costs the results of the present study are compared in Box 3 with some other scenario studies.

Scenario modelling uses a large number of assumptions. By calculating the energy system for multiple scenarios, the sensitivity of various assumptions are analysed. For example, the assumptions regarding energy demand, sustainability goals and potential for solar, wind, and $CO_2$ storage differ for ADAPT and TRANSFORM. However, the results (e.g., optimal nuclear capacity, system costs, etc.) can also differ for assumptions that are the same for both scenarios. Three 'what-if' analyses were conducted to investigated variants of assumptions suspected of having a significant impact on the results. These what-if analyses were performed only for the TRANSFORM scenario. The sensitivities of the results to these what-if analyses are presented and discussed in Section 3.2.

In Section 3.3 the role of SMRs is examined in more detail. In the scenarios SMRs are used in industry with co-production of electricity and heat (process steam).

## 3.1 Nuclear versus no nuclear

### 3.1.1 Primary energy

A future Dutch energy system with nuclear energy has more energy sources at its disposal than the same energy system without nuclear energy. Because the assumed wind energy potential has been fully utilised and other energy sources are also used to the maximum (e.g. biomass), have relative high costs (e.g. geothermal) or are limited by greenhouse gas emissions (e.g. fossil energy), more primary energy is used in the energy system with nuclear energy than in the system without. This is evident from Figure 3.1, which shows the primary energy supply for the system with nuclear energy (indicated as Baseline) and the changes if no new nuclear capacity is added to the system (NoNuclear). In all other figures in this section, the comparison of the energy system with nuclear energy and without nuclear energy is presented in the same way.

In the system with nuclear energy, the share of uranium in the total primary energy supply in 2050 is 18% (ADAPT) and 19% (TRANSFORM). In that year, the total primary energy supply in the system without nuclear energy is 11% (ADAPT) to 14% (TRANSFORM) lower than in the system with nuclear energy. It should be noted that uranium has a relatively large share in the primary energy supply because the efficiency of the NPPs is much lower (approx. 35%)

than for other forms of energy (for wind and solar energy this is 100%). This means that the share of nuclear energy in electricity generation is much smaller as will be shown in the next paragraph. The fact that the total primary energy supply for TRANSFORM is lower than for ADAPT is related to the scenario assumptions in which there is less demand for energy, mobility, and goods in TRANSFORM due to behavioural changes (which is not assumed for ADAPT).

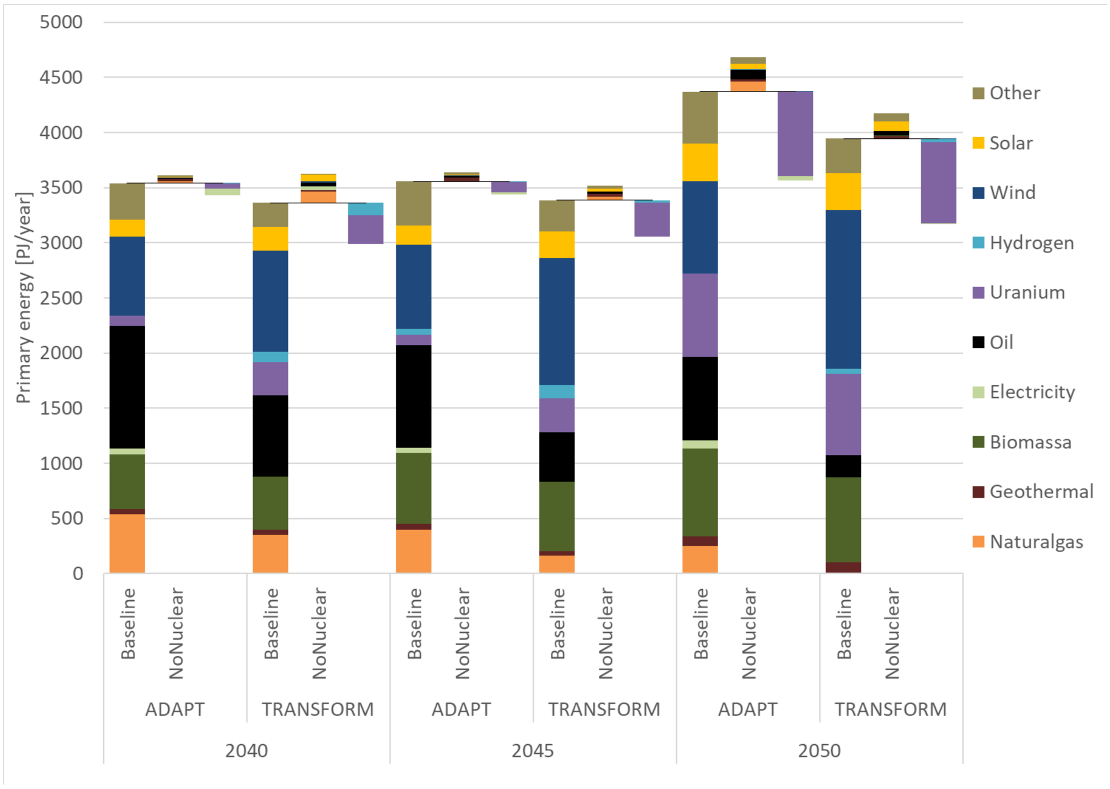



Figure 3.1: Primary energy supply for ADAPT and TRANSFORM and changes in primary energy carriers in case of no new nuclear

## 3.1.2 Electricity generation capacity

Investments in new nuclear capacity in ADAPT and TRANSFORM are shown in Table 3.1 for both large NPPs and SMRs for the years 2040, 2045 and 2050. Although for both scenarios it is assumed that the first new large NPP can be operational in 2035, this is not yet cost-efficient in that year. In 2040 the capacity of the existing Borssele NPP is also shown due to its long-term operation up to 2043. In ADAPT, large NPPs will not appear until 2050. In that year, the maximum capacity of 6 GW will be deployed in ADAPT. In TRANSFORM, the deployed capacity for new large NPPs in 2040 and 2045 is 2.4 GW. This capacity will grow to the capped maximum of 6 GW in 2050, the same level as in ADAPT. Because the electricity demand in TRANSFORM is considerably higher than in ADAPT, the need for electricity production capacity in TRANSFORM is also higher. This explains the difference in deployment of new nuclear capacity between the two scenarios in 2040 and 2045.

Table 3.1: Deployment of nuclear energy in ADAPT and TRANSFORM (baseline) and in case of no new nuclear energy (NoNuclear)

| Scenario | | 2040 | | | | | 2045 | | | | | 2050 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Large NPP | | SMR | | | Large NPP | | SMR | | | Large NPP | | SMR | | |
| | | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | |
| | | (Max: 3.5[b] GW) | Electricity | (Max: 0.45 GW) | Electricity | Heat | (Max: 4.5 GW) | Electricity | (Max: 0.9 GW) | Electricity | Heat | (Max: 6 GW) | Electricity | (Max: 2.1 GW) | Electricity | Heat |
| ADAPT | Baseline | 0.5[a] | >8060 | 0.45 | 231 | 8133 | 0.0 | 8058 | 0.9 | 195 | 8042 | 6.0 | 8556 | 2.1 | 5722 | 2423 |
| | NoNuclear | 0.5[a] | >8600 | | | | | | | | | | | | | |
| TRANSFORM | Baseline | 2.9[b] | 8451 | 0.45 | 324 | 7286 | 2.4 | 8311 | 0.9 | 204 | 7545 | 6.0 | 8381 | 2.0 | 3890 | 4286 |
| | NoNuclear | 0.5[a] | >8600 | | | | | | | | | | | | | |

[a] Long-term operation Borssele NPP

[b] Including long-term operation Borssele NPP

In 2040 and 2045, SMRs are deployed in both scenarios up to the maximum capacity, see Table 3.1. This also applies to ADAPT in 2050, but in the TRANSFORM scenario the capacity remains in 2050 just below the maximum. This is because industrial steam demand in 2050 is lower in TRANSFORM than ADAPT. The stated SMR capacities concern the sum of SMRs with low and high pressure steam supply. Section 3.3 discusses the deployment of SMRs in industry in more detail.

The total electricity generation capacity and its composition in 2040, 2045 and 2050 for ADAPT and TRANSFORM is shown in Figure 3.2. The figure illustrates that electricity generation capacity consists of wind energy (onshore and offshore), solar PV and nuclear, supplemented with thermal capacity for peak supply (hydrogen and natural gas). It should be noted that in both scenarios the assumed maximum capacity of wind power (onshore and offshore) is deployed in all years. The capacity for solar PV is however below the assumed maximum in both scenarios and all presented years. The maximums have been set to take into account the expected rate of expansion of wind and solar power, the available spatial area for these types of renewable energy generation and the social acceptance thereof (see Table 2.4 for the assumed maximum capacities). The total installed production capacity is higher in TRANSFORM than in ADAPT due differences in the maximum capacities for both scenarios and difference in electricity demand.

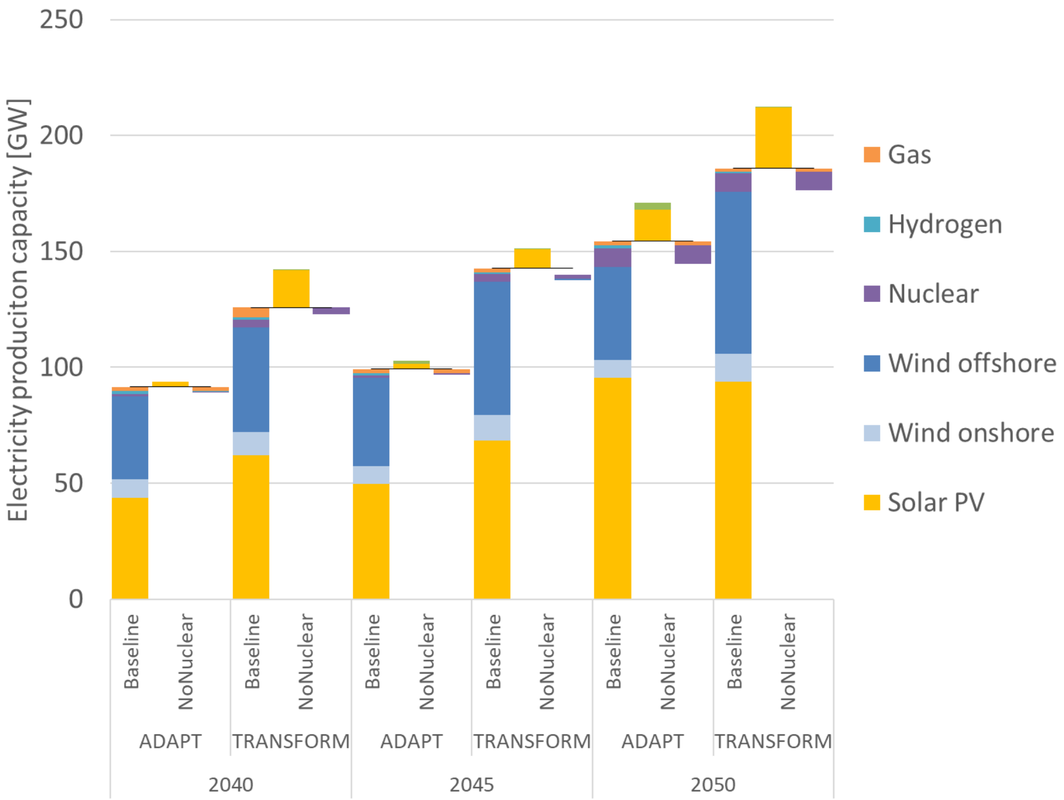



Figure 3.2: Electricity production capacity in ADAPT and TRANSFORM (baseline) and changes in electricity consumption in case of no new nuclear capacity

In the NoNuclear variant, no new large NPPs and SMRs are built. However, the policy for the long-term operation of the existing Borssele NPP is maintained up to 2043. Figure 3.1 shows that the NoNuclear variant the total production capacity increases, in TRANSFORM in 2050 approx. 10% and in ADAPT approx. 4.5%. The increase mainly occurs with solar PV. However, the electricity production from solar energy is much lower than that from nuclear energy due to a lower availability (i.e. the sun does not always shine). This reduces the total electricity production in the NoNuclear variant without new NPPs, see next section.

## 3.1.3 Electricity generation

In 2024, total Dutch electricity generation amounted to 120 TWh, of which 2.8% was nuclear energy (CBS). In 2050, electricity generation may increase by a factor of 3.3 in the ADAPT scenario and by a factor of 4.7 in the TRANSFORM scenario. The share of nuclear energy in the generation mix increases in 2050 to 14.5% for ADAPT and 10.5% for TRANSFORM, see Figure 3.3. The modelling of both scenarios shows that large NPPs can be deployed most cost-optimally in the base load. SMRs, on the other hand, are used for most hours of the year to supply heat to industry. At times of low electricity production from wind and sun, SMRs are also deployed for electricity production. This can be deduced from the full load hours for electricity and heat production listed in Table 3.1. When abundant solar and wind energy is available, the surplus is used for hydrogen production (flexibility function), battery charging, and electricity export. The NPPs do not respond to this oversupply and continue to produce electricity.

In the NoNuclear variant, almost all electricity is produced by wind turbines and solar PV, i.e. in 2050 97% for ADAPT and 99% for TRANSFORM.

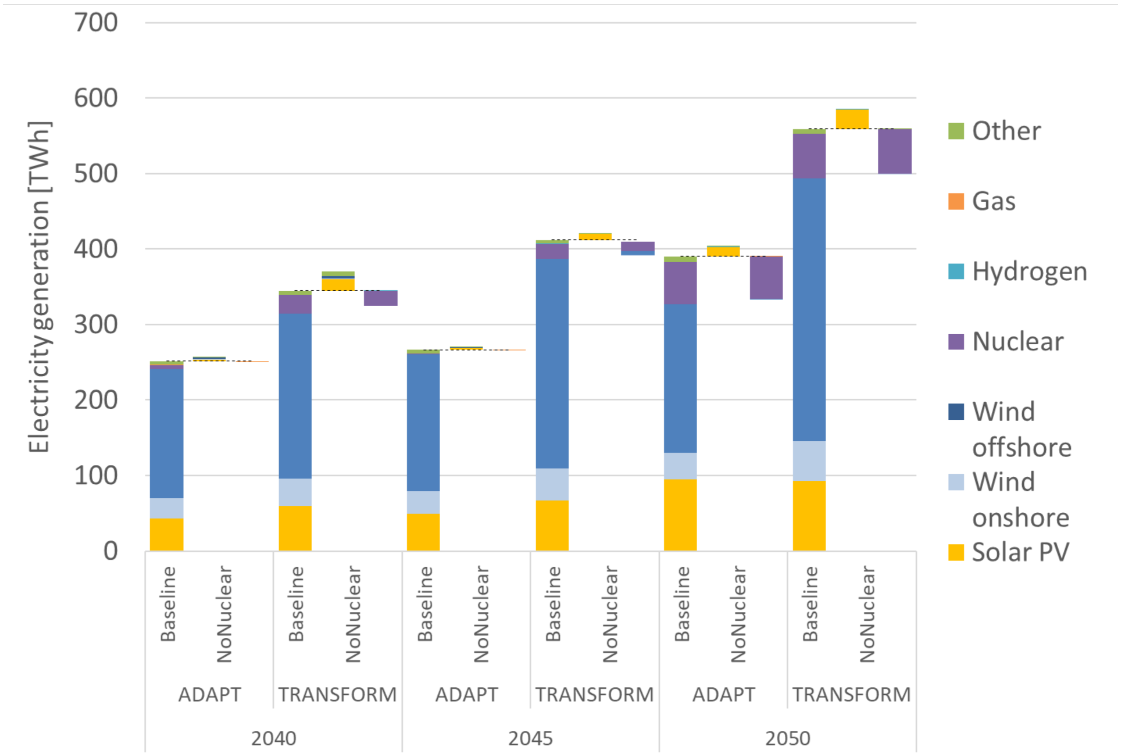



Figure 3.3: Electricity generation mix in ADAPT and TRANSFORM (baseline to no nuclear)

## 3.1.4 Electricity demand

Electricity demand consists of domestic consumption and net exports. Domestic electricity consumption increases in both scenarios due to electrification of mobility and electrification of heat demand in the built environment, agriculture and industry sectors. In addition, the growing demand for green hydrogen (produced with electrolysers) also explains the increase in electricity consumption. Compared to ADAPT, the TRANSFORM scenario is more ambitious with regard to production of sustainable feedstocks for industry and sustainable fuels for maritime shipping and aviation. This explains the substantial higher electricity consumption in TRANSFORM compared to ADAPT in Figure 3.4. This figure shows the electricity demand of the various end-use sectors and the net exports to neighbouring countries (or net imports if number is negative).

In the NoNuclear case, total electricity consumption decreases especially in the later years, because less electricity is produced due to a limited production capacity (i.e. no new NPPs, maximum wind and solar capacities, see previous paragraphs). In 2040 and 2045 there is a slight decrease in electricity demand (less than 5%), with the exception of TRANSFORM in 2040 due to slightly higher demand for hydrogen production. In these years the increase and decrease per sector, in particular that of hydrogen and export, are limited and partly cancel each other out. In 2050, when the nuclear share in the baseline scenario is substantially larger, a much clearer difference becomes apparent in the NoNuclear variant: the decrease in electricity consumption occurs mainly in the demand for hydrogen (further explained in the next section), net-import and for heating in the built environment due to energy efficiency improvements (insulation and more efficient heat pumps).

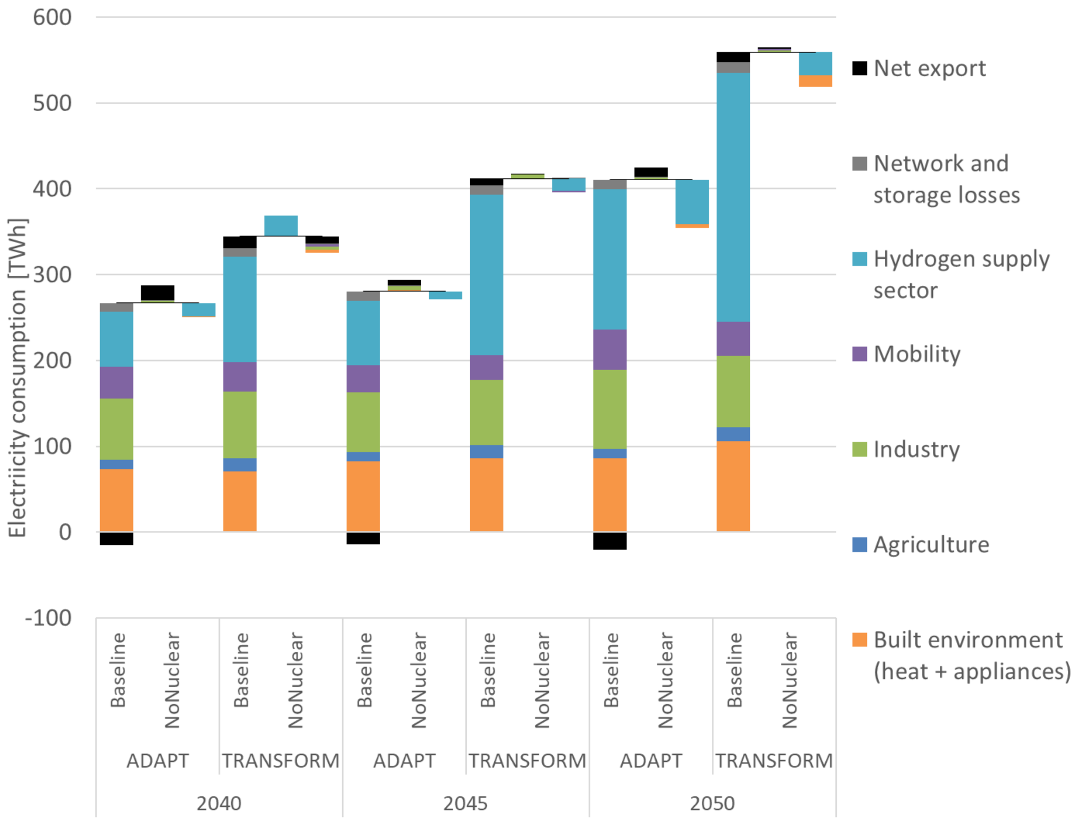



Figure 3.4: Electricity consumption by sector for ADAPT and TRANSFORM (baseline) and changes in electricity consumption in case of no new nuclear capacity

## 3.1.5 Hydrogen demand and supply

In both scenarios, almost all hydrogen is produced by electrolysers. The resulting electricity demand is relatively high, especially in TRANSFORM, as already shown in Figure 3.4. That graph also showed that lower electricity production in the NoNuclear scenario due to a limited production capacity (no new NPPs, maximum wind and solar capacities) decreases the electricity demand for hydrogen production, especially in the later years. Figure 3.5 shows the hydrogen demand in ADAPT and TRANSFORM. The decrease in hydrogen demand if no new nuclear capacity is built occurs mainly in production of synthetic fuels for aviation and shipping (i.e. bunker fuels). The reduction in the amount of synthetic fuels is compensated by increase of biofuel use. In TRANSFORM also hydrogen imports decrease (shown as a negative value for net export) due to changes in hourly price differentials.

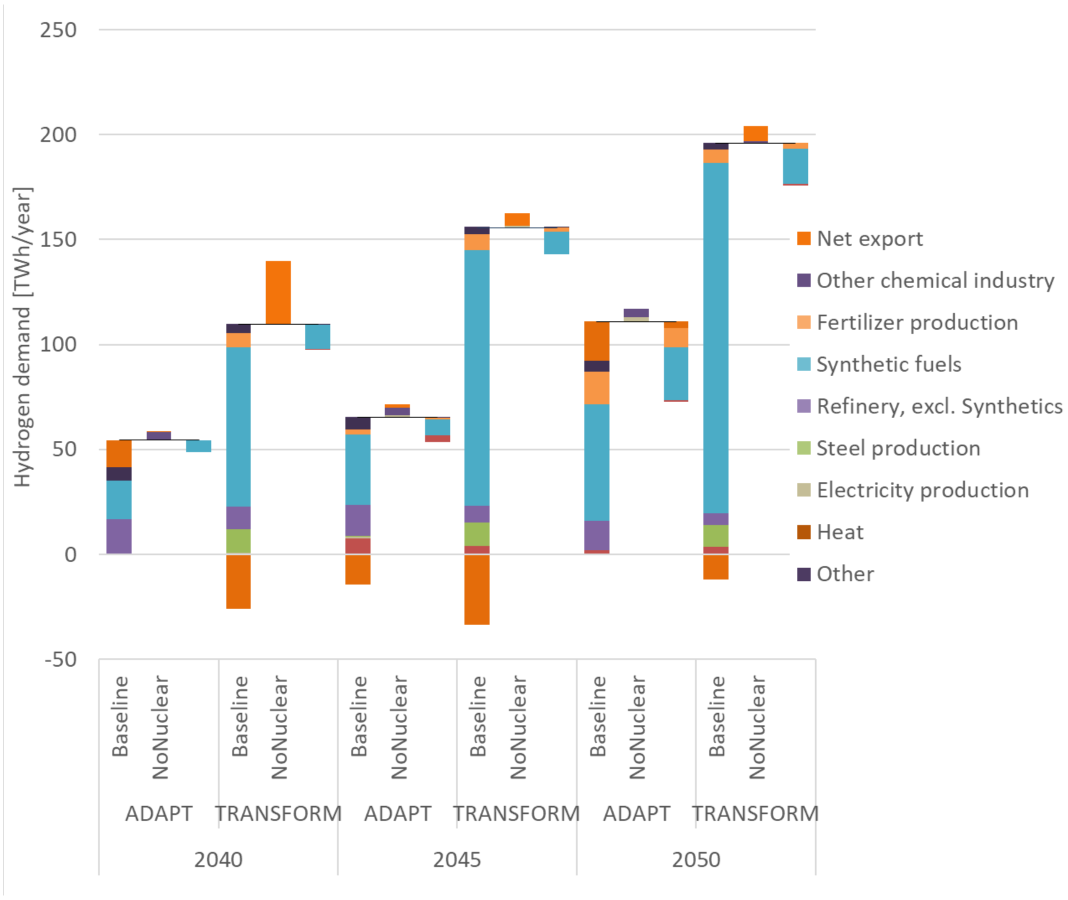



Figure 3.5: Hydrogen demand by subsector for ADAPT and TRANSFORM (baseline) and changes in hydrogen demand in case of no new nuclear capacity

## 3.1.6 Import and export of electricity and hydrogen

At certain times, the Dutch energy system generates significantly more electricity and hydrogen than it consumes, while at other times, it experiences shortages. Trading these surpluses and deficits with neighboring countries plays a crucial role in enhancing the system's flexibility. Over the course of a year, this can result in net imports or exports of these commodities, depending on the balance of supply and demand.

The import and export of electricity and hydrogen is a result of coupling OPERA with COMPETES-TNO (explained in Section 2.1.3). The OPERA model uses the import or export volume of COMPETES-TNO with the associated price, but can adjust the volume to a limited extent (+/- 10%) during cost optimization.

The analyses of electricity and hydrogen demand in previous sections showed that the presence or absence of new nuclear production capacity has an impact on the exchange of electricity and hydrogen with foreign countries. For this reason, these changes are further examined here. Figure 3.6 shows the separate import and export volumes of electricity and hydrogen as well as the net export (negative figures: net import) for the baseline scenarios and the changes therein in the event of no investment in new nuclear capacity (NoNuclear). The separate import and export volumes shown are the sum of the hourly imports and exports from different countries. Note that the Netherlands is connected to several countries, with each country a different price.

*Electricity import and export*
In ADAPT, there is a net import of electricity in all three years shown in Figure 3.6, approximately 3% to 6% of total electricity supply. In the NoNuclear variant, the net import decreases compared to the baseline and changes into a limited net export in 2040 (less than 1% of total electricity supply). This is a striking outcome, because in the baseline of ADAPT 2040, no new large-scale NPP is present yet.. This effect stems from the SMRs, where, in the case of NoNuclear, heat supply to industry is taken over by increased electrification. This electricity is generated using additional renewable electricity production, creating more surpluses that are exported and reducing net imports. In TRANSFORM, net electricity is exported in all three years (approximately 2% to 4% of total electricity supply). The changes between the baseline and NoNuclear variant are small in all three years. In TRANSFORM, electricity is exported mainly in periods with a lot of sun and wind. The presence or absence of new NPPs hardly affects this export.

*Hydrogen import and export*
For ADAPT, Figure 3.6 shows net hydrogen exports in 2040, net imports in 2045 and net exports again in 2050, respectively 24%, 29% and 17% of domestic hydrogen production. The fact that hydrogen is exported in one year and imported in another year is a result of cost optimization and is related to the developments in hydrogen demand and cost-efficient investments in hydrogen production capacity in ADAPT. In the NoNuclear variant, the changes for import and export of hydrogen are limited compared to the baseline. In TRANSFORM, there is a net import of hydrogen demand in all years (31% of domestic hydrogen production in 2040, 27% in 2045 and 6% in 2050). Domestic hydrogen production is limited by the maximum available electricity, which means that hydrogen demand must be partly covered by imports. In the NoNuclear variant, hydrogen imports decrease remarkably enough in 2045 and 2050. As the bottom graph of Figure 3.6 shows, this is the balance of less import and less export, a phenomenon that also occurs in 2050 in the NoNuclear variant of ADAPT. The explanation for this must be sought in the differences in foreign hydrogen prices compared to the costs of domestic production.

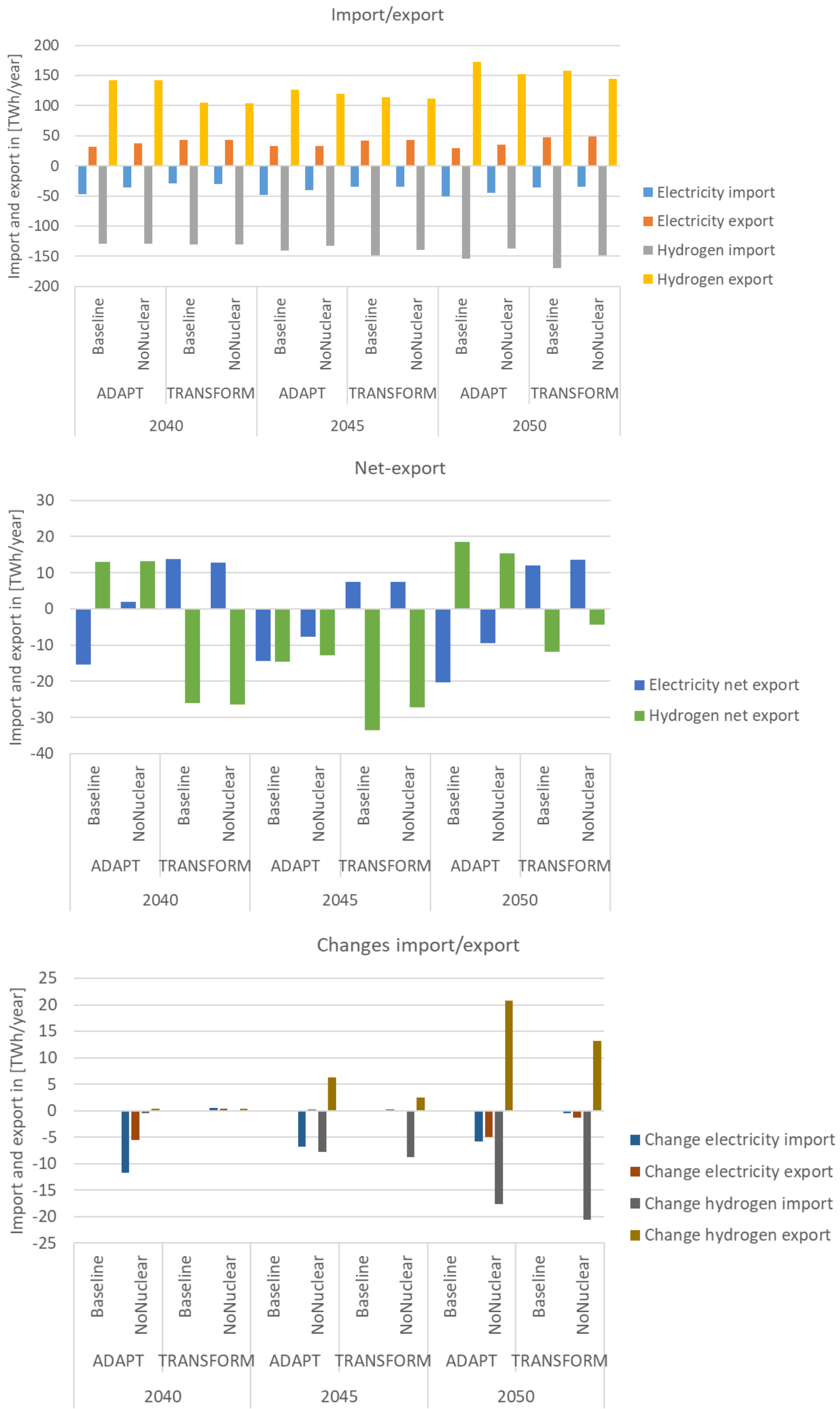



Figure 3.6: Electricity and hydrogen import (negative numbers) and export (positive numbers), net-export and changes in import and export for ADAPT and TRANSFORM (baseline) and in case of no new nuclear capacity

### 3.1.7 System costs[14]

The OPERA model calculates annual system costs. The total system costs are the sum of the annual capital costs[15], the annual operation and maintenance costs, energy transport costs and imported energy costs minus the revenues from exported energy. The ADAPT and TRANSFORM scenarios with nuclear have lower system costs than the same scenarios without nuclear. This is not surprising because a cost-optimized energy system was calculated with the OPERA model, and the model selected new nuclear power capacity. A scenario without nuclear will therefore have higher system costs. Figure 3.7 shows the system costs for both scenarios in 2050 for ADAPT and TRANSFORM with and without nuclear power (green bars). The figure is a waterfall graph that indicates for different elements of the energy system whether there is an increase (blue bars) or decrease in costs (orange bars) per system element.

The total system costs of the ADAPT scenario are higher in 2050 than for TRANSFORM. This also applies to 2040 and 2045. This can be explained on the one hand by the difference in assumptions about the demand for energy, mobility and products, but is also caused by the higher fossil energy consumption in ADAPT. The ADAPT scenario is more sensitive to changes in fossil energy prices than TRANSFORM.

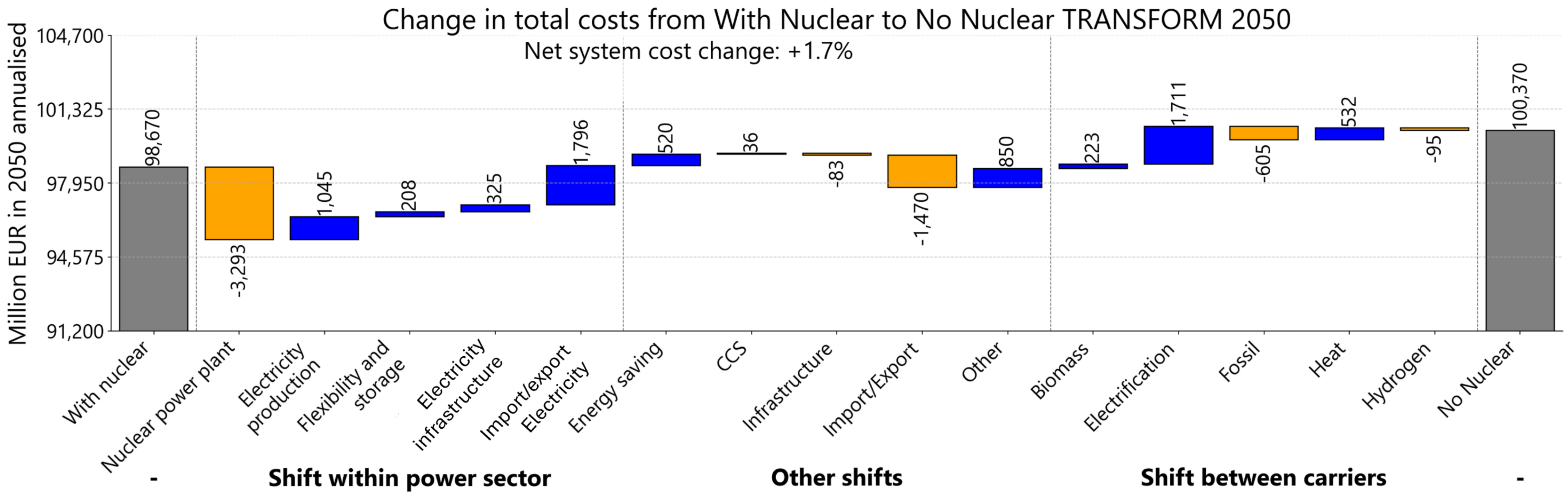
Figure 3.7 shows that in 2050 the total system costs of the scenario without nuclear energy for ADAPT are 1.6% (€$_{2015}$ 1.8 billion) higher than for the scenario with nuclear energy. For TRANSFORM this difference is 1.7% (€$_{2015}$ 1.7 billion). The various cost elements of the energy system are shown in the graph in three groups: 'changes within electricity production' (left side), 'changes between energy carriers' (right side) and 'other changes' (in the middle).

In ADAPT, the net electricity production costs in the system with nuclear energy are in 2050 €$_{2015}$ 3 billion higher than when nuclear energy is not included in the energy system. In TRANSFORM, the net electricity production costs in the system with and without nuclear energy are almost the same. Besides the differences in electricity generation costs — particularly between nuclear and solar PV — there are also changes in costs and revenues from electricity imports and exports across the two scenarios due to price and volume changes. In both scenarios, within the category 'electricity production', annual expenditures in a system with nuclear energy for flexibility, energy storage and electricity infrastructure are lower than in a system without nuclear energy, but these cost differences are relatively small.

In both scenarios, the largest cost difference within the category 'shifts between energy carriers' stems from electrification in the end-use sectors. Compared to scenarios without new nuclear, a system with new nuclear capacity allows more electricity to be consumed in demand sectors. Less efficient options with lower investment costs are used, e.g. electric boilers instead of heat pumps or air heat pumps instead of ground heat pumps. In the category 'other changes', the changes in import and export of energy are relatively large. This mainly concerns changes in hydrogen, but also applies to changes in natural gas use, especially in ADAPT. In TRANSFORM, this leads to higher costs for an energy system with new nuclear capacity, while in ADAPT it leads to lower costs. In both scenarios, cost savings are made on insulation in the system with nuclear: for example, less money is spent on home insulation.

[14] See for an in-depth study on the impact of nuclear energy on system costs (Kooiman, Scheepers, Beres, Hakvoort, & Meeuwsen, 2025).

[15] The annual capital costs is per technology determined from the investment costs, the economic life and the discount rate. Because optimization is based on societal costs, a discount rate of 2.25% is used.



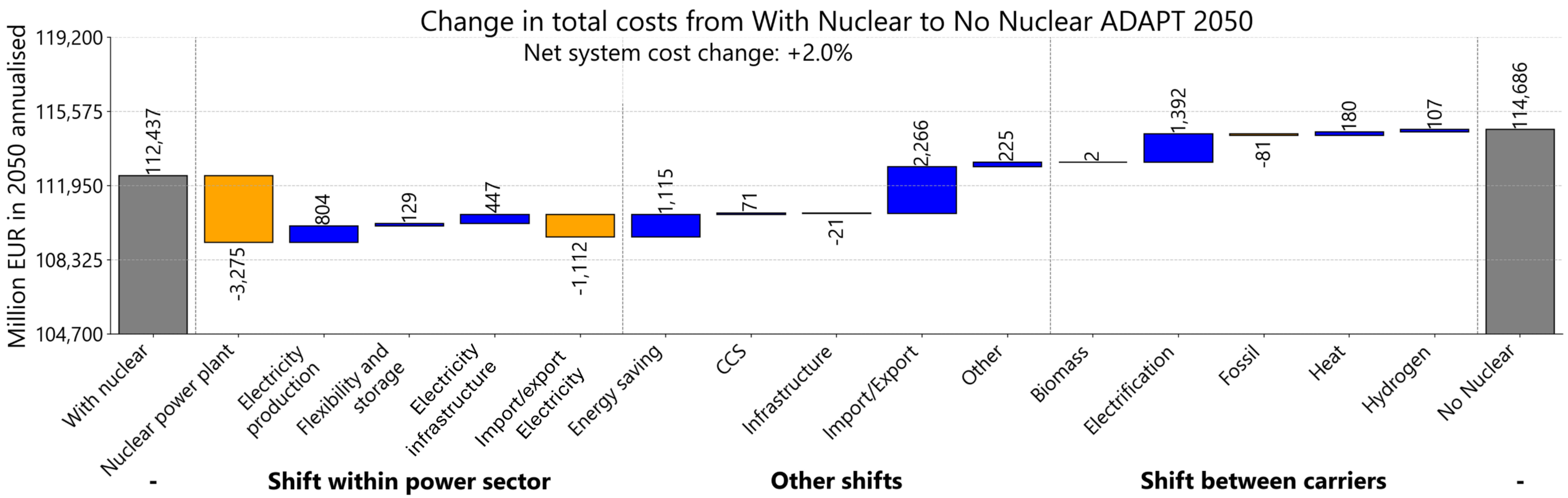




Figure 3.7: Changes in total system costs (in €2015) [16] for ADAPT 2050 and TRANSFORM 2050 with and without nuclear (blue indicates a cost increase and orange a cost decrease)

[16] In €2024 system costs are approximately 30% higher.

## Box 3 – Comparison with other scenario studies

*TNO and PBL have previously conducted scenario studies using the OPERA model in which new nuclear power plants were included in a future sustainable energy system for the Netherlands. The table below provides an overview of the capacities for nuclear power plants, wind and solar for the various scenarios in 2050. The TNO scenario study of 2024 finds that the system costs of a future Dutch energy system with nuclear energy are approximately 1 to 2% lower than an energy system without nuclear energy. This is in line with the current study. PBL observes in their study that more wind capacity and nuclear energy lead to more hydrogen production and more direct electrification. This is also consistent with the current study.*

| Study | Scenario/variant | Large NPPs (GW) | SMRs (GW) | Wind offshore (GW) | Wind onshore (GW) | Solar-PV (GW) | Reference |
|---|---|---|---|---|---|---|---|
| Scenario study TNO 2024 | ADAPT | 3 | 1.55 | 40 | 7.8 | 109 | (Scheepers, et al., 2024) |
| | TRANSFORM | 3 | 2 | 70 | 12 | 132.1 | |
| | Industry variants | 3 | 0.6-1.2 | 70-65.6 | 11.3 | 70.3-81.0 | |
| TVKN study PBL 2024 | | 3.5 | Not available | 69.5 | 9.9 | 95.8-132 | (Daniëls & Strengers, 2024) |

# 3.2 What-if analyses

Assumptions made for the scenarios, and the energy system modelling are uncertain and can influence the results as presented in the previous section. Therefore, some parameters and boundary conditions have been changed. These what-if or sensitivity analyses concern the following assumption changes:

- *No ceiling for nuclear, wind energy and solar PV capacities (NoRES-NUC-CAP).*
  In ADAPT and TRANSFORM, the maximum assumed capacity for wind and nuclear energy is used in 2050. If these restrictions are not imposed, the total system costs could be lower. To explore the cost-optimal deployment of wind energy, solar PV, and nuclear energy without capacity constraints, a what-if analysis was conducted in which the maximum capacity limits for these technologies were removed.

- *High investment costs nuclear energy (Nuc2xCost).*
  The investment costs for new large NPPs appear to have a lot of uncertainty due to construction delays and cost overruns. Therefore, the investment costs of large nuclear plants could be substantially higher than assumed for ADAPT and TRANSFORM. SMRs are still in development and not yet commercially available. This causes uncertainty about the investment costs for SMRs. Appendix D provides further

explanation of these uncertainties. In this what-if analysis, it is assumed that the investment costs doubled for both large nuclear plants and SMRs. Note that if the investment costs are lower than assumed in the base case scenarios, this would have little effect on the installed nuclear capacity because this is already almost fully deployed in the base case. The system costs will be slightly lower though.

- *Changes in European electricity and hydrogen demand (TYNDP24).*
  The development of the electricity and hydrogen demand and supply in neighbouring countries is uncertain. In a what-if analysis, the electricity and hydrogen demand from the TYNDP DE scenario of 2022 has been replaced by the TYNDP DE scenario of 2024 (see for data Appendix B). The changes in the projections vary significantly by country, with demand projections for some countries increasing and others decreasing. Overall, conventional electricity demand is estimated to be slightly higher in TYNDP24 than in TYNDP22, and hydrogen demand is estimated to be slightly lower. With this new scenario, the optimal electricity and hydrogen production capacities in the EU countries have been recalculated using the COMPETES-TNO model and new electricity and hydrogen exchange flows and prices have been used as input for the OPERA model.

The what-if analyses were only performed for the TRANSFORM scenario because TRANSFORM has a higher energy demand and new NPPs become cost-efficient faster than ADAPT. The what-if analysis without production capacity ceilings was only performed for 2050 because that was the year in which the highest maximum capacities in TRANSFORM were assumed.

### 3.2.1 Electricity generation capacity

Table 3.2 shows that investing in large NPPs is not cost-efficient if there is no capacity ceiling for wind, solar and nuclear energy in 2050 (NoRES-NUC-CAP). Instead of large NPP's more is invested in wind offshore capacity (25 GW additional; 95 GW in total) and solar PV (40 GW additional; 120 GW in total) in this what-if scenario (see Figure 3.8). Offshore wind is more cost-efficient than onshore wind due to the relatively large number of full-load hours. Without applying a capacity ceiling, extra offshore wind energy capacity is realised close to the coast. However, this will not be possible in reality. If the additional offshore wind energy capacity is realised far from the coast, offshore wind will be more expensive, and wind onshore will probably be the preferred option for capacity expansion. It should be emphasized that this what-if scenario does not take into account the feasibility of these capacity expansions and the social acceptance.

Investing in SMRs still seems attractive, although the optimal capacity to be installed in 2050 in the NoRES-NUC-CAP scenario is smaller compared to the base case. In this what-if scenario, SMRs are still used for heat and electricity production, but electricity production drops significantly.

Also if investment costs of large NPPs and SMRs doubles compared to the assumptions in the base case (Nu2xCosts scenario), large NPPs are no longer cost-efficient, but SMRs are still realised, albeit with lower capacity than in the base case (see Table 3.2). As in the NoRES-NUC-CAP what-if scenario, heat supply remains the main output of these SRMs in the Nu2xCost scenario, but electricity production decreases. In both what-if scenarios, heat supply by SMRs remains cost-efficient, although the competitive advantage with other heat sources diminishes. Electricity production by SMRs becomes less attractive. Figure 3.8 shows that a smaller nuclear production capacity in the Nu2xCost what-if scenario is partly compensated by an expansion of solar PV.

Table 3.2: Deployment of nuclear energy in TRANSFORM (baseline) and in what-if cases

| Scenario | 2040 | | | | | 2045 | | | | | 2050 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Large NPP | | SMR | | | Large NPP | | SMR | | | Large NPP | | SMR | | |
| | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | | Capacity [GW] | Full load hours | Capacity [GW] | Full load hours | |
| | (Max: 3.5 GW) | Electricity | (Max: 0.45 GW) | Electricity | Heat | (Max: 4.5 GW) | Electricity | (Max: 0.9 GW) | Electricity | Heat | (Max: 6 GW) | Electricity | (Max: 2.1 GW) | Electricity | Heat |
| TRANSFORM Baseline | 2.9[b] | 8451 | 0.45 | 324 | 7286 | 2.4 | 8311 | 0.9 | 204 | 7545 | 6.0 | 8381 | 2.0 | 3890 | 4286 |
| NoRES-NUC-CAP | Not analysed | | | | | | | | | | 0.0 | - | 1.0 | 7591 | 486 |
| Nuc2xCost | 0.5[a] | >8600 | 0.45 | 504 | 7814.7 | 0.0 | - | 0.9 | 144 | 7792 | 0.0 | - | 1.3 | 5809 | 2299 |
| TYNDP24 | 1.3[a] | 8520 | 0.45 | 304 | 7288.3 | 0.9 | 8318 | 0.9 | 243 | 7560 | 4.3 | 8375 | 1.8 | 4344 | 3780 |

[a] Long-term operation Borssele NPP

[b] Including long-term operation Borssele NPP

In the third what-if scenario, TYNDP24, the differences with the base case scenario are smaller. However, the nuclear capacity of large NPPs is much lower than in the baseline scenario due to lower electricity demand for hydrogen production because significantly more hydrogen is imported driven by lower hydrogen demand in other countries in the base case. The SMR capacity is the same in 2040 and 2045 as in the base case scenario, but in 2050 the SMR capacity grows less. The deployment of the large NPPs in this what-if scenario is comparable to the base case, which can be seen from the number of full load hours. The SMR results show a slight shift from heat to electricity production.

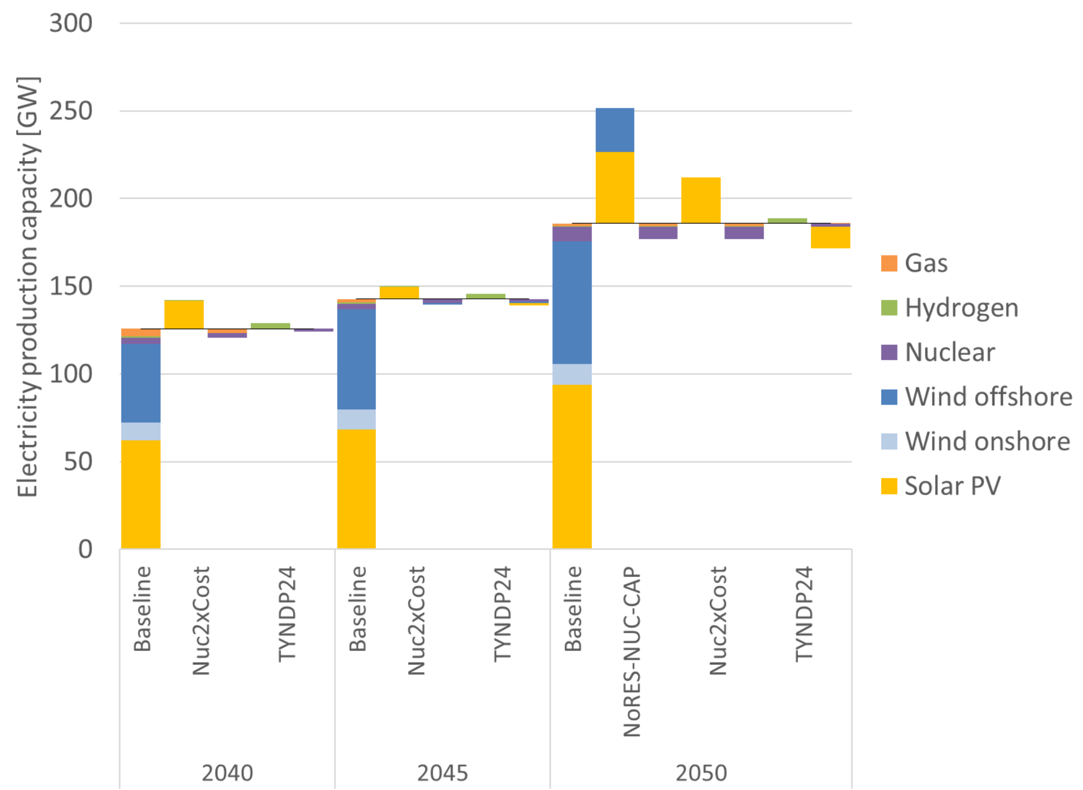



Figure 3.8: Electricity production capacity in ADAPT and TRANSFORM (baseline) and changes in capacity for the what-if case

## 3.2.2 Electricity generation

Because the capacity of NPPs in all three what-if scenarios is lower than in the base case scenarios, electricity production from nuclear energy decreases. This is illustrated in Figure 3.9. In the NoRES-NUC-CAP what-if case (only 2050), loss of electricity production from nuclear energy is compensated by more electricity production from wind and sun. Total electricity production is even 8% higher than in the base case, because, without a ceiling, more wind and solar energy capacity can be installed.

In the Nuc2xCosts case, the decline in electricity production from nuclear energy is compensated by more production from solar PV and other sources (i.e. residual gases from oil refineries and biomass processes). Because the increase in production cannot fully compensate for the loss of nuclear electricity production, demand is lower in the what-if case. As a result, total electricity production will be 4% and 6% lower in 2045 and 2050, respectively.

In the TYNDP24 what-if case, less electricity is produced in all three years compared to the baseline. This is due to a much larger hydrogen import compared to the base case. As a result, the electricity demand for electrolysis in the what-if case is lower. Although less nuclear energy is used, the cost difference between this what-if case and the baseline is smaller than in the TRANSFORM scenario without nuclear energy. This applies not only to nuclear energy, but also to solar PV and wind energy.

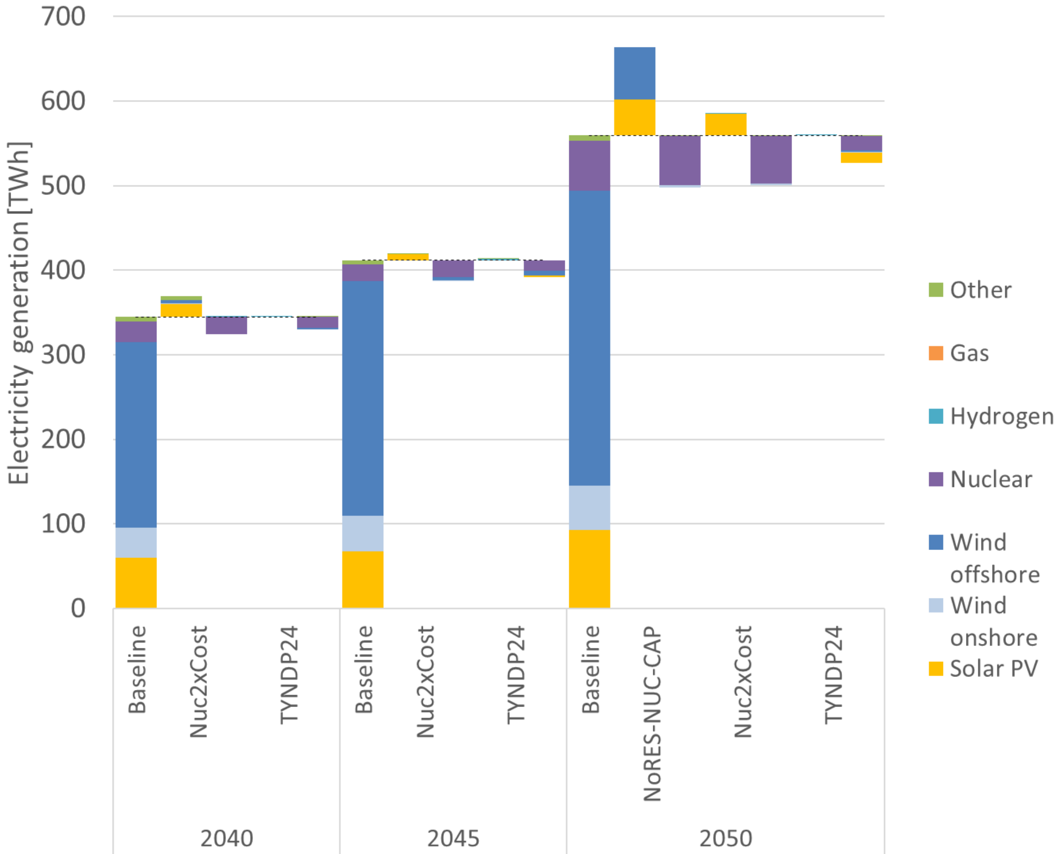



Figure 3.9: Electricity generation mix in TRANSFORM (baseline) and changes in the generation mix for the what-if cases

## 3.2.3 System costs

Table 3.3 shows the change in total system costs for the three what-if cases compared to TRANSFORM (baseline) in 2050. For comparison, the difference with TRANSFORM without nuclear is also shown. Removing the cap for the different electricity production technologies in noRES-NUC-CAP results in a system with 3% lower total system costs than the baseline. The OPERA model can deploy the optimal capacity for these technologies, without taking the caps into account.

The what-if case with doubled investments for nuclear energy (Nu2xCosts) has almost the same system costs as the baseline. No large NPPs are deployed, but SMRs still are, though fewer than in the baseline. As a result, the cost difference between this what-if scenario and the baseline is much smaller than in the TRANSFORM scenario without nuclear energy.

The what-if scenario based on different foreign electricity and hydrogen demand assumptions (TYNDP24) results in a 3% increase in system costs for the Dutch energy system. In this scenario, most cost components are comparable to or slightly lower than those in the baseline. The key difference lies in hydrogen exports, which are significantly reduced compared to the baseline. As a result, the lower export revenues provide less compensation for the overall system costs.

Table 3.3: Changes in total system costs (€$_{2015}$)[17] in 2050 for the what-if cases compared to TRANSFORM (baseline)

| | NoNuclear | NoRES-NUC-CAP | Nuc2xCost | TYNDP24 |
|---|---|---|---|---|
| Change in Million € | +1,700 | -3,417 | +400 | +3,302 |
| Change in % | +1.7% | -3,5% | +0,4% | +3,3% |

# 3.3 Role of Small Modular Reactors

Small Modular Reactors (SMRs) are defined in the present study as nuclear reactors with a capacity of 150 MW$_e$. These are able to provide both heat (in the form of steam) and electricity. They are able to operate in a range of conditions from producing only heat, only electricity, or cogenerating both simultaneously. Two different SMRs, a Low Pressure (LP) and High Pressure (HP) variant, are used in this report differentiated by the pressure and temperature at which they can provide steam for industrial heat applications. The LP SMRs are able to provide process heat in the form of steam at a temperature of 100 - 200°C, and the HP SMRs are able to provide process heat in the form of steam at a temperature of 200 - 400°C. The OPERA model is free to place either type of SMR in any region to meet the heat and electricity demand there, the only restrictions built into the model is the maximum total SMR capacity. This capacity is the combination of both high and low pressure SMRs and is 0.45GW$_e$, 0.90 GW$_e$ and 2.10 GW$_e$ for 2040, 2045, and 2050 respectively. The SMRs in this study are intended to have a capacity of 150 MW$_e$ each. However, as the model provides installed SMR capacity in a non-discrete way and no minimum capacity is set per region, in many of the years there are capacities well below this 150 MW$_e$ in some regions. The minimum capacity per region to be considered suitable for placement of an SMR is instead set to 50 MW$_e$[18], in order to avoid losing too much capacity from the modelled system while still maintaining realistic results for the SMR allocation. This results in regions having no SMR capacity allocated to them and between 5-30 % of total SMR capacity nationally being removed. This cutoff is only used in the current section of the analysis of what role the SMRs play in the wider system, and is not used in the rest of this report. The data for capacity per region in each year and in each scenario before and after this cut-off is implemented is available in Appendix H of this report.

## 3.3.1 SMRs in the base case scenarios

This section analyses the allocation of SMR capacity nationally and regionally for the base case TRANSFORM and ADAPT scenarios. The national results are presented before the 50 MW$_e$ cut-off is implemented and shows both the LP, HP, and the total combined capacities of these two SMR types. For the national results having the combined total capacities available is important as this is the only parameter with a restriction built into the OPERA model. The regional capacities are then presented after the 50 MW$_e$ cut-off is implemented. The regional results are shown as the HP and then the LP SMR capacities per region per year for each base case scenario.

[17] In €$_{2024}$ system costs are approximately 30% higher.
[18] A lower capacity SMR might deviate too much from the assumed generic SMR.

*SMR capacity*
Figure 3.10 shows the national allocation of LP, HP, and total SMR (LP and HP combined) capacities for the base case scenarios. The maximum capacity allowed by the system for the combined total of HP and LP SMR capacities are in $GW_e$ is [0.450, 0.900, 2.100] for 2040, 2045, and 2050 respectively. The model is allowed to choose freely between placing each type of SMR within the constraints of the maximum of the two categories combined. For ADAPT this maximum capacity is reached each year, while for TRANSFORM it is only reached in 2040 and 2045 with the capacity in 2050 being 1.997 $GW_e$. This is not necessarily the economically optimal solution but only the optimal solution within the constraints of the scenario. One of the 'what if' scenarios explores what would happen if the constraint on nuclear capacity is removed, see Section 3.3.2.

With the capacities shown in Figure 3.10 there will be approximately 12-14 150 $MW_e$ SMRs placed nationwide by 2050. The majority of these will be LP SMRs, with slightly more LP SMR capacity in TRANSFORM in 2050 than in ADAPT in 2050. However, due to the regional spread of this capacity, and some regions not being allocated sufficient capacity for an SMR there will be fewer SMRs when the regional allocations are taken into account. Additionally, in practice SMRs will be deployed in a variety of capacities, not only 150 $MW_e$. Due to these factors the focus is instead placed on installed capacity in $GW_e$, rather than a number of SMRs.

Examining the SMR allocation per region is an important parameter for understanding the role they play in the Dutch energy system. With the cut-off at 50 $MW_e$ most regions are considered to be less suitable for SMR placement and are therefore excluded for this analysis. This removes around 5-30% of the original capacity, the original data as well as the data with the cut-off is available in Appendix H.

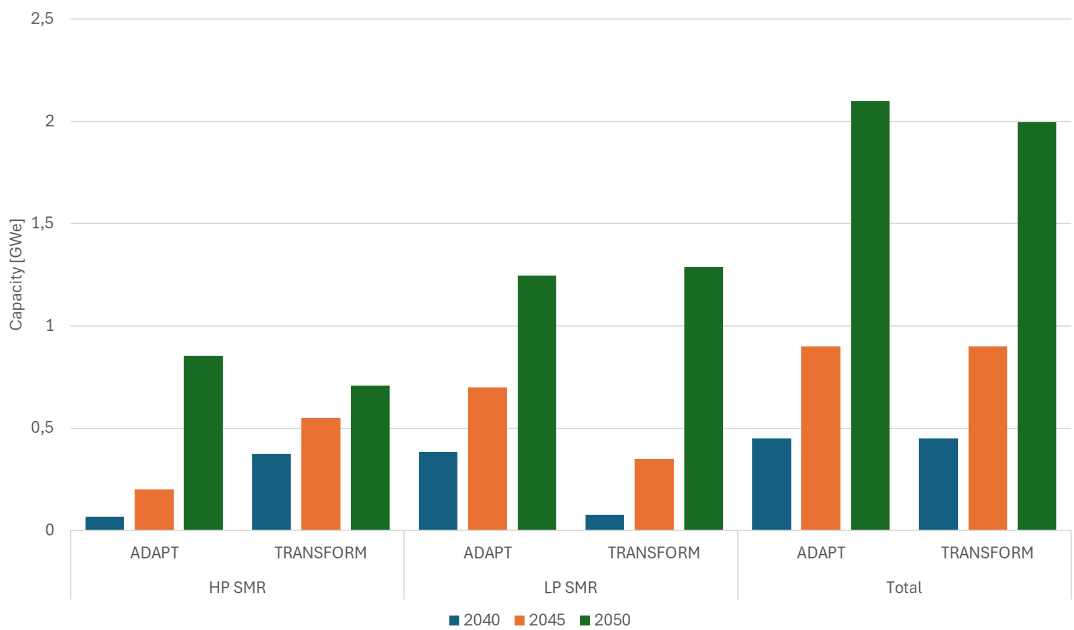



Figure 3.10: Capacities ($GW_e$) of both low and high pressure SMRs and combined nationally.

Figure 3.11 shows the HP SMR capacity per region, after the 50 $MW_e$ cut-off is implemented, for ADAPT and TRANSFORM in 2040, 2045, and 2050. Three regions are allocated sufficient

SMR capacity above this cut-off, South Holland, Limburg, and Zeeland. South Holland is particularly well suited with the largest capacities of HP SMRs allocated to this region. In 2050 this region takes 75 % in ADAPT and 66% in TRANSFORM of the total HP SMR capacity. This demand for HP heat in South Holland is driven by two industries: the refinery and the chemical sectors. South Holland has by far the largest heat demand for these two industries of any region in the Netherlands.

The LP SMR capacities, after the cut-off is implemented, in the base case scenarios are shown in Figure 3.12. Four regions are found to be suitable for LP SMR deployment: Limburg, South Holland, Zeeland, and North NL. The difference with the HP SMRs is that more industrial sectors have a low-temperature heat demand and that these industrial sectors have a larger geographical spread. Limburg in TRANSFORM has the largest capacity in 2050, and South Holland has the largest capacity in ADAPT in 2050. The relatively large capacity in Limburg can be partially explained by the relatively high electricity production from LP SMRs in Limburg in 2050 in TRANSFORM. The distance from Limburg to offshore electricity production is relatively large. Furthermore, Limburg is well connected to electricity networks in Belgium and Germany. This makes electricity production in this region cost-efficient because it reduces the transport of electricity over the high-voltage network.

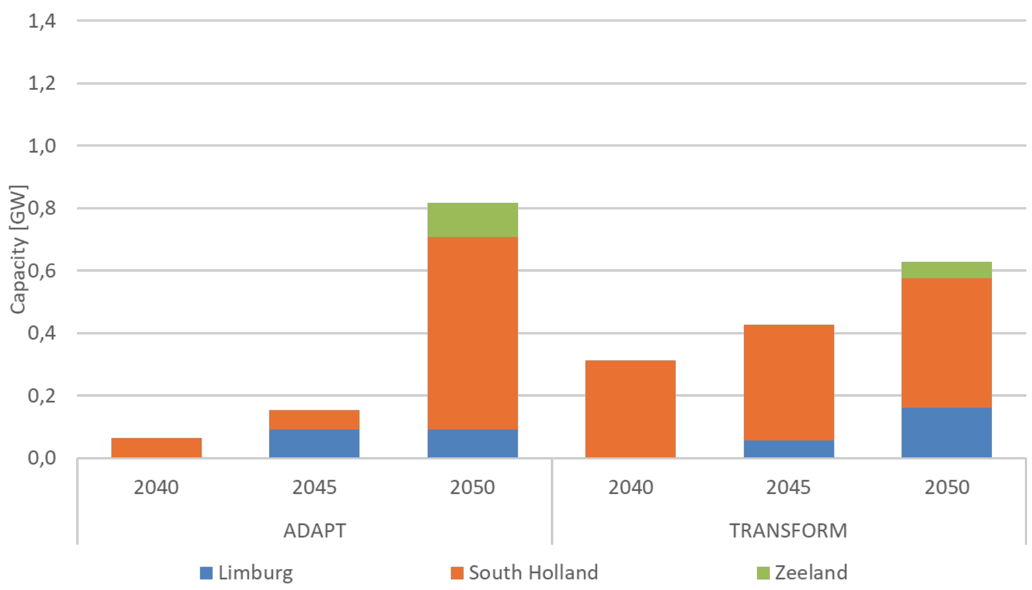



Figure 3.11: Regional breakdown of high pressure SMR capacity in $GW_e$ for the base case scenarios

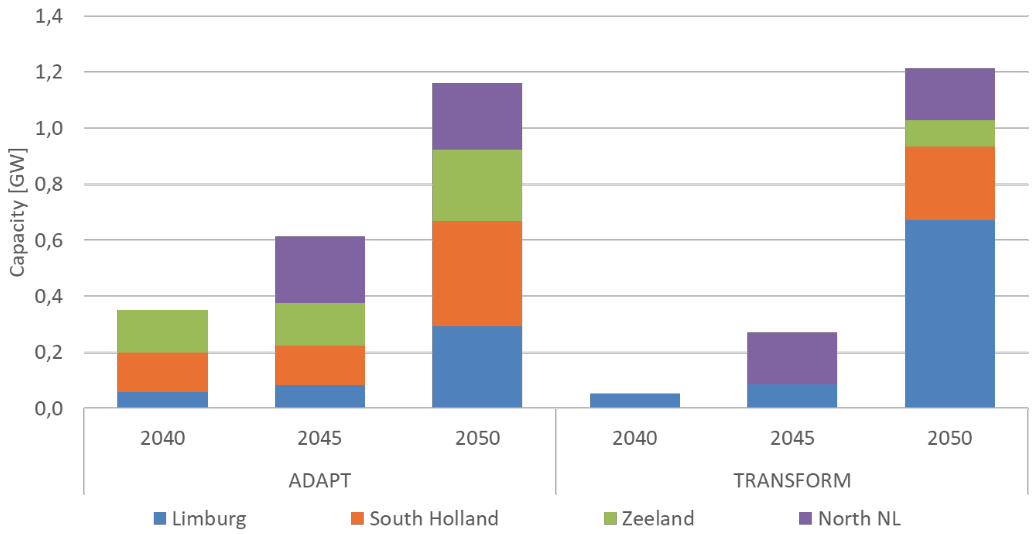



Figure 3.12: Regional breakdown of low pressure SMR capacity in $GW_e$ for the base case scenarios

*SMR electricity supply*
To understand the allocation and utilization of SMRs, the energy demand was examined in greater detail. In particular, the demand for industrial heat within the temperature ranges in which SMRs operate was examined. This helps explain how SMRs play a role in the energy system. In Figure 3.13 the heat and electricity output from the SMRs for the years 2040, 2045, and 2050 is given for both the base case scenarios. The analysis clearly shows that the primary role of SMRs is to provide heat for industrial applications. Since HP SMRs are dedicated to supplying industrial heat, their contribution to the electricity sector remains limited. However, LP SMRs play a small but still significant role in electricity generation. This contribution is particularly notable in the TRANSFORM scenario for the year 2050.

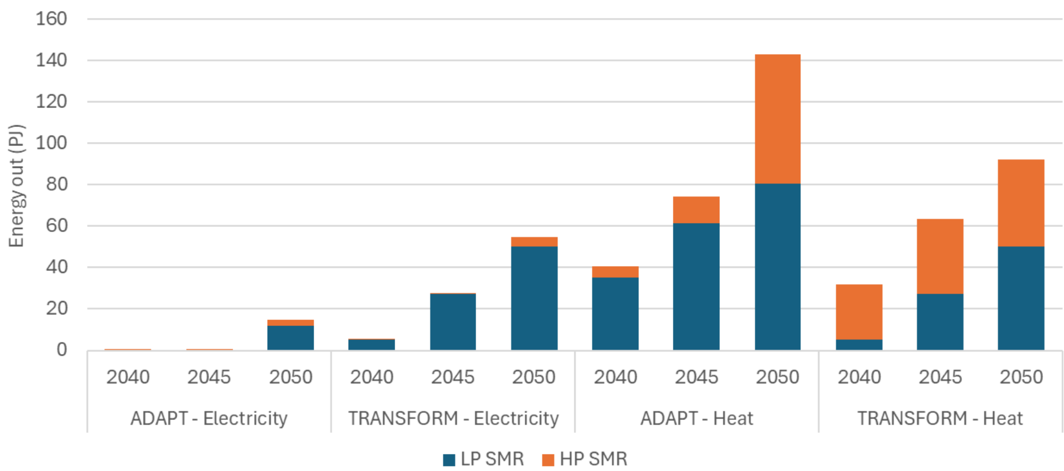



Figure 3.13: Electricity and heat production from SMRs in the base case scenarios

While the main role of SMRs is to provide heat they also play a considerable role in the electricity supply in some regions in 2050. Nationally LP and HP SMRs combined, supply around 1 - 1.5% of the total electricity demand annually. The majority of this, 83% and 79% in TRANSFORM and ADAPT respectively, is from LP SMRs. SMRs contribute to balancing the electricity system by producing electricity for several hundred hours per year when electricity production from wind and solar energy is low. While SMRs are present in 4 regions, only in two regions are they used for significant amounts of electricity production: Limburg and North NL. In Table 3.4 the proportion of the total annual electricity demand that is met with SMRs in Limburg and North Holland in 2050 is shown.

Table 3.4: Percentage of electricity consumed per region that is supplied by SMRs in 2050

| | TRANSFORM | | ADAPT | |
|---|---|---|---|---|
| | HP SMRs | LP SMRs | HP SMRs | LP SMRs |
| Limburg | 3.4 % | 15.1 % | 2.2 % | 5.2 % |
| North NL | 0 % | 4.2 % | 0 % | 5.2 % |

*SMR heat supply*

Examining the heat supplied by SMRs in more detail shows the strong position of LP SMRs and HP SMRs in the supply of industrial process heat by 2050. As can be seen from Figure 3.14, this is particularly the case for the LP SMRs in 2050, where they take 69% and 73 % of the heat demand in ADAPT and TRANSFORM in the temperature range of 200-400 °C. In 2050 the proportion of heat demand supplied by SMRs in each category of heat are somewhat similar, but this is not the case in 2040 and 2045. This difference is at least partly due to the difference in the ways heat is supplied by other heat sources in these two scenarios (e.g. waste gases, electric boilers, biomass boilers, electric heat pumps).

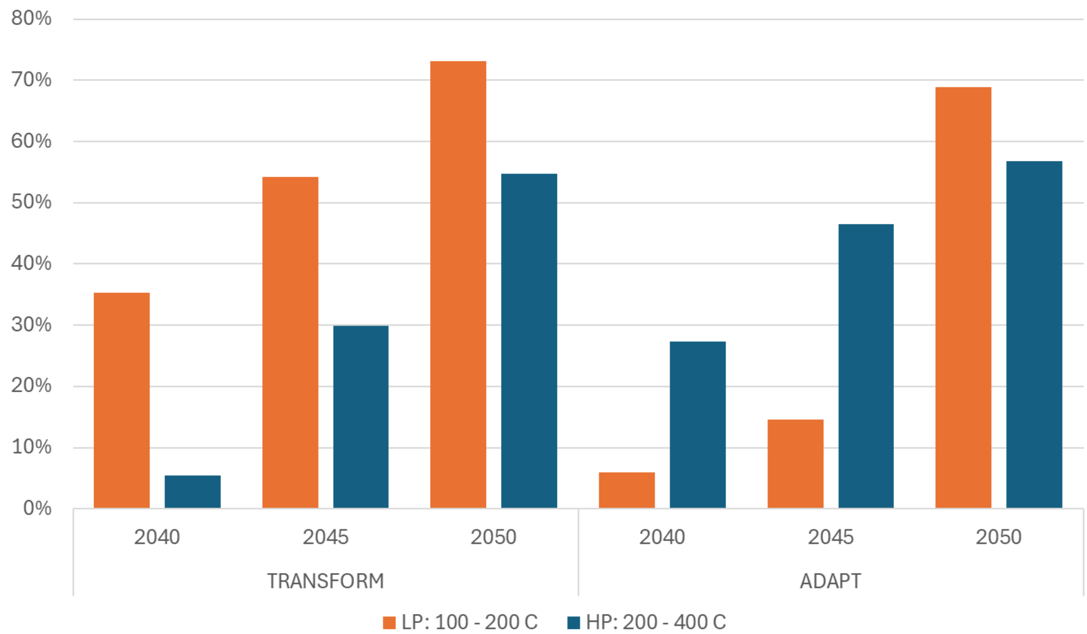



Figure 3.14: Proportion of industrial heat demand in the 100 - 200 °C heat and the 200-400 °C heat categories provided by SMRs in the base case scenarios

Examining the heat demand by industrial sub-sectors indicates what the SMRs are being used for on a national level, particularly in 2050 as they are the dominant heat supplier in the temperature categories they operate in. For both temperature categories of heat looked at for SMRs in ADAPT and TRANSFORM there is no large increase in heat demand between 2040 and 2050, and in fact there is generally a small decrease in total heat demand. This means that the increase in the proportion of heat being supplied by SMRs is SMRs replacing existing heat supply sources (e.g. waste gas boilers, electric boilers, biomass boilers, electric heat pumps) rather than adding to the total heat supply available. In the base case TRANSFORM scenario (see Figure 3.15) the heat demand in the 100-200 °C category is primarily focused on the chemicals industry, constituting 53% of the total heat demand in 2050 for this category. The food and beverage industry, the refinery industry, and 'other' industry all also individually make up between 11-13% of the total heat demand in this category each in 2050. In TRANSFORM for the 100-200 °C heat supply category mainly industrial heat pumps are being replaced, which are used to upgrade lower grade heat. Heat pumps supply approximately 80%, 55% and 22% of heat demand in 2040, 2045, and 2050 respectively.

Heat demand at 200-400 °C in TRANSFORM undergoes a decline between 2040 and 2050, mainly caused by a steady decrease in refinery heat demand due to reduced demand for fossil oil products. The heat demand for refineries decreases from 42.8 PJ a year to just 17.1 PJ a year from 2040 to 2050. This decline in demand means that the increased proportion of heat coming from SMRs is being driven by two factors: the overall decrease in demand and the increase in supply from SMRs. Heat supply from waste gas boilers in refineries in this heat category decrease from 31.5 PJ to just 3.5 PJ a year between 2040 and 2050.

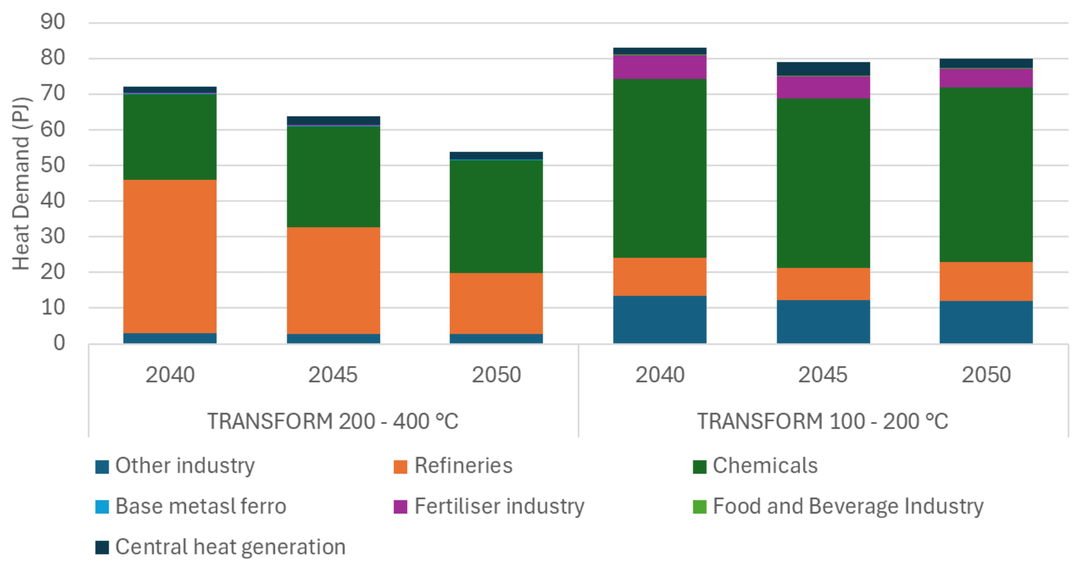



Figure 3.15: Heat demand by sector for two temperature categories in the TRANSFORM scenario

Examining the heat demand in the base case ADAPT scenario also shows the role of SMRs. There is a small decrease in heat demand in the 200-400 °C range between 2040 and 2050, while there is a small increase in heat demand in the 100-200 °C temperature range. This relatively steady heat demand during these years comes even with a large increase in the proportion of heat coming from SMRs as shown in Figure 3.14. This means as with TRANSFORM, that the SMRs are directly replacing other heat sources as they come online instead of adding to the total heat supply available. Comparing the proportion of heat from SMRs in ADAPT in the 200-400 °C shown in Figure 3.14 and the total heat demand per industry in this temperature category in ADAPT in Figure 3.16 demonstrates how SMR heat is being used. The refinery industry dominates this area of heat demand, ranging from 79% of the total heat demand in 2040 to 63% in 2050. The HP SMRs are directly replacing other heat suppliers, with the main sources being replaced being waste gas boilers. The can be seen mainly in the refinery industry, with waste gas boilers in the refinery industry going from providing 83% of all heat in 2040 to just 13% in 2050. The majority of this decrease in supply of heat from waste gas boilers in the refinery sector comes between 2045 and 2050, with the supply from this source going from 70.5 PJ to just 12.6 PJ per year. This decrease is compensated for mainly by an increase in SMR heat supply and an increase from other sources such as waste gas combined heat and power in the chemicals industry and electric boilers. The heat category of 100-200 °C is supplied by the LP SMRs, and as shown in Figure 3.16, the demand in this category in ADAPT increases approximately 10% between 2040 and 2050. This increase comes mainly in the chemical industry, increasing from a total demand of 67.6 PJ in 2040 to 74.7 PJ in 2050, and the refinery sector, increasing from 27.4 PJ to 29.0 PJ from 2040 to 2050. In 2040 the main heat supply technology in this temperature category is heat pumps, supplying around 53% of all heat. This heat supply from heat pumps decreases to 22% of the total by 2050. This is mainly being replaced by SMRs and to a lesser extent electric boilers.

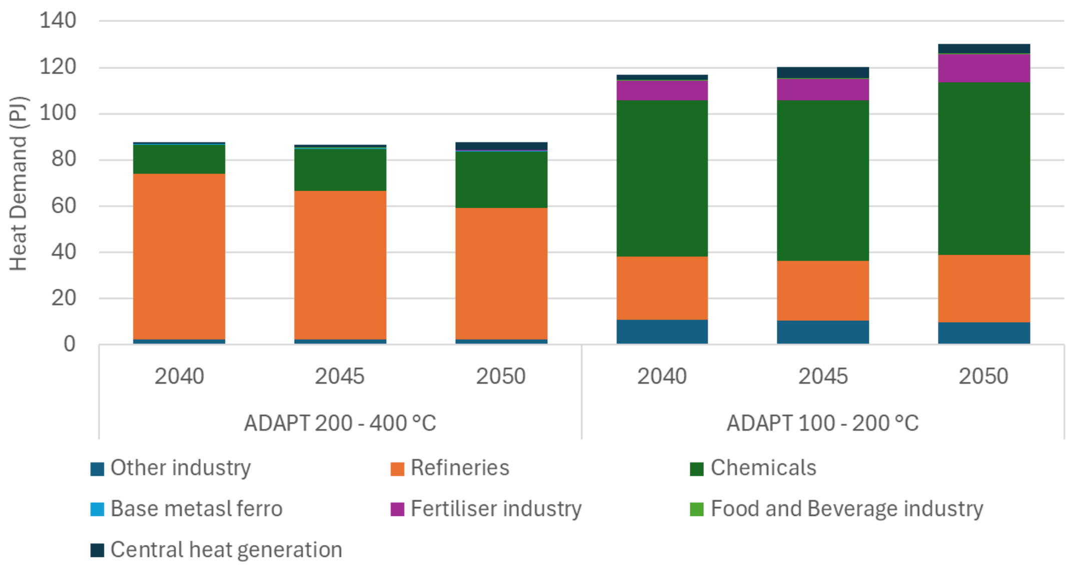



Figure 3.16: Heat demand by sector for two temperature categories in the ADAPT scenario

## 3.3.2 SMRs in the what if scenarios

There are three 'what if scenarios relevant to understanding the role that SMRs play in the energy system: the double nuclear investment cost scenario (Nu2xCost), the no limit on the capacity of RES and nuclear scenario (NoRES-NUC-CAP), and the TYNDP24 scenario. The NoRES-NUC-CAP scenario is only simulated for 2050 and not 2040 or 2045. All of the what if scenarios are based on the TRANSFORM scenario. The maximum allowable capacities for SMRs remain the same as in the base case [0.45 GW, 0.90 GW, 2.1 GW] for 2040, 2045, and 2050, except for in the NoRES-NUC-CAP scenario. Additionally, the 50 $MW_e$ cut-off for SMR capacities per region is also implemented for the regional analysis of these results.

*SMR Capacity*
Figure 3.17 shows the capacity of the LP and HP SMRs in the three what if scenarios and the base case TRANSFORM scenario for 2040, 2045, and 2050. The main result from the what if scenarios is that while the total SMR capacity is lower in 2050 for all scenarios compared to the base case TRANSFORM scenario, there is still significant SMR capacity being allocated by the model. The majority of the lost capacity in the what if scenarios come from the LP SMRs. For the scenario with higher nuclear investments (Nu2xCost) and the TYNDP24 scenario the SMR capacity still reaches the maximum allowed capacity in the system in 2040 and 2045. This shows the relative importance of SMRs to the system and the robustness of their deployment, that even with double the investment costs they are still cost efficient. In 2050 the decrease between the base case and the Nu2xCost scenario is around 0.72 $GW_e$ or a decrease of approximately 36%. Additionally, there is still relatively large deployment of SMRs in the scenario with no cap for renewable electricity and nuclear capacity (NoRES-NUC-CAP), with approximately half of the capacity of the base case remaining in this scenario in 2050. This indicates that even if renewables could be placed anywhere without restriction it would still be more optimal to have some SMR capacity in the system.

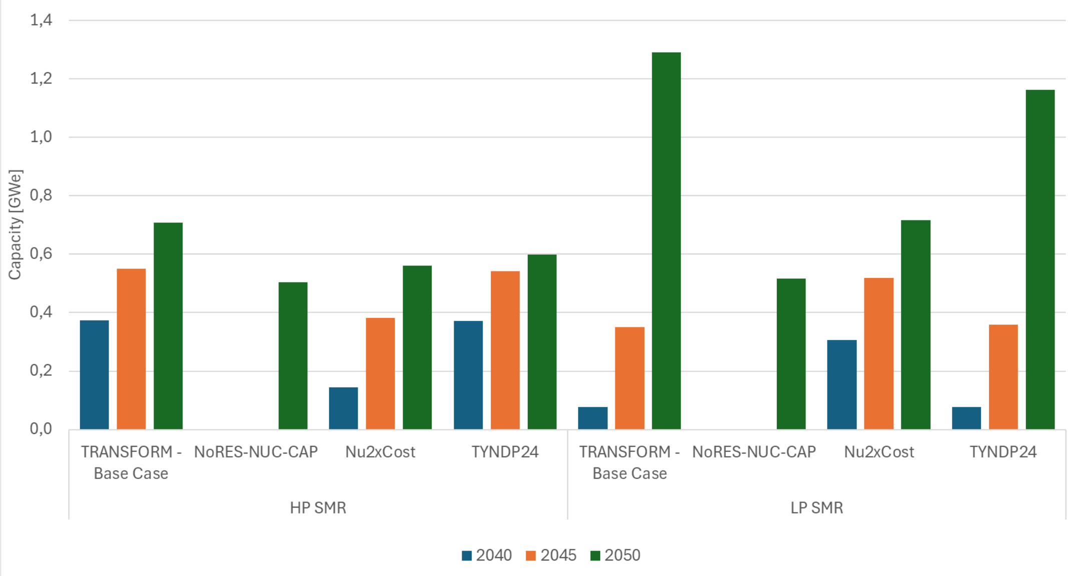



Figure 3.17: HP and LP SMR capacities ($GW_e$) for the base case TRANSFORM and the what if scenarios

Examining the regional allocation of the SMR capacity for the what if scenarios compared to the base case TRANSFORM scenario shows the impact of the different conditions imposed. Figure 3.18 shows the HP SMR capacities per region, this again is after the cut-off of 50 MWe is implemented. There are changes to the geographic distribution of SMRs, with Limburg receiving no HP SMRs in the NoRES-NUC-CAP scenario or Nu2xCost scenario. The region of South Holland does not suffer from a large reduction in overall HP SMR capacity in all scenarios. There is an interesting increase in capacity in Zeeland between the base case and the NoRES-NUC-CAP scenario. This is a rearrangement of the optimally deployed SMR capacity between South Holland and Zeeland.

As with the HP SMRs the LP SMRs capacities in most regions are lower in the what if scenarios than in the base case TRANSFORM scenario. The same regions are generally allocated LP SMRs in the what if scenarios compared to the base case, with Limburg, South Holland, Zeeland, and North NL being allocated LP SMRs in 2050 in all scenarios except in the NoRES-NUC-CAP scenario. In this scenario no capacity is allocated to North NL. Additionally, in the Nu2xCost scenario there is more SMR capacity allocated in 2040 and 2045 compared to the base case TRANSFORM. In both scenarios Limburg suffers the greatest loss in capacity. This is because SMR capacity in Limburg is used for electricity production in the base case, which is in the NoRES-NUC-CAP scenario replaced by renewable sources or too expensive in the Nu2xCost scenario. The overall increase in LP SMR capacity seen in the Nu2xCost scenario comes at the same time as the decrease in HP SMR capacity. This indicates that the LP SMRs are more preferable when the investment cost increases.

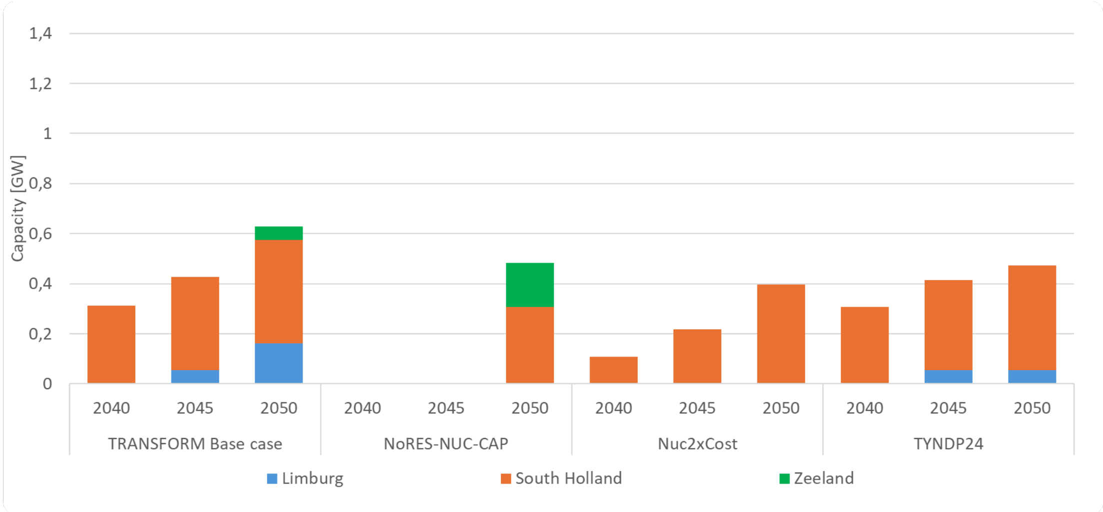



Figure 3.18: HP SMR capacity in the base case TRANSFORM and the what if scenarios

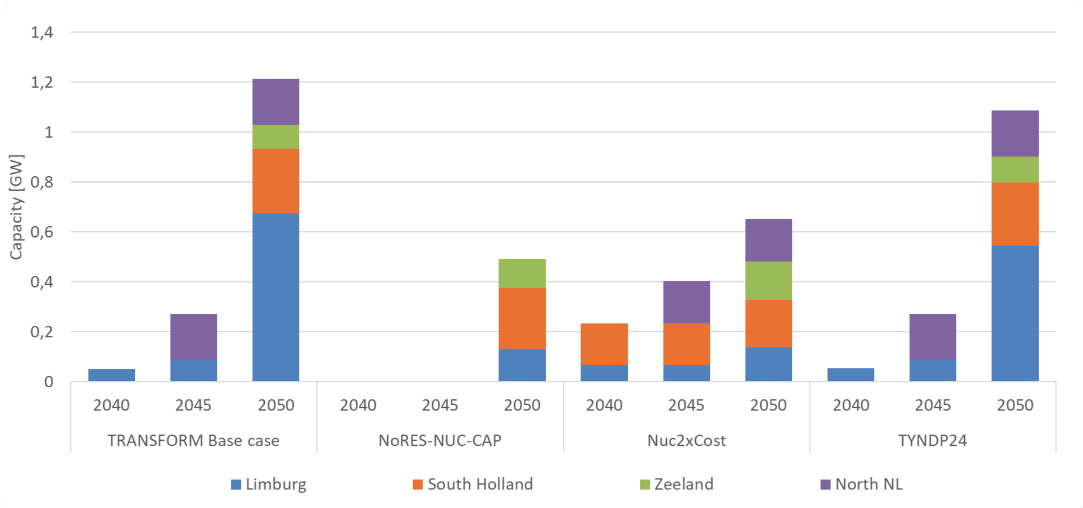



Figure 3.19: LP SMR capacities per region in the base case TRANSFORM and what if scenarios

*SMR electricity supply*

The SMR use case in the what if scenarios are similar to their use in the base case scenarios, with the largest focus being on the supply of heat to industry. There is also less electricity production in all what if scenarios compared to the base case TRANSFORM scenario. This drop in electricity is a much larger proportional decrease than the decrease in heat supply seen in the what if scenarios compared to the base case. The smallest amount of electricity supplied is in the NoRES-NUC-CAP scenario, with other sources being able to provide more electricity than before. This decrease in electricity supplied in the what if scenarios shows that system is less reliant on electricity supply than heat supply by SMRs.

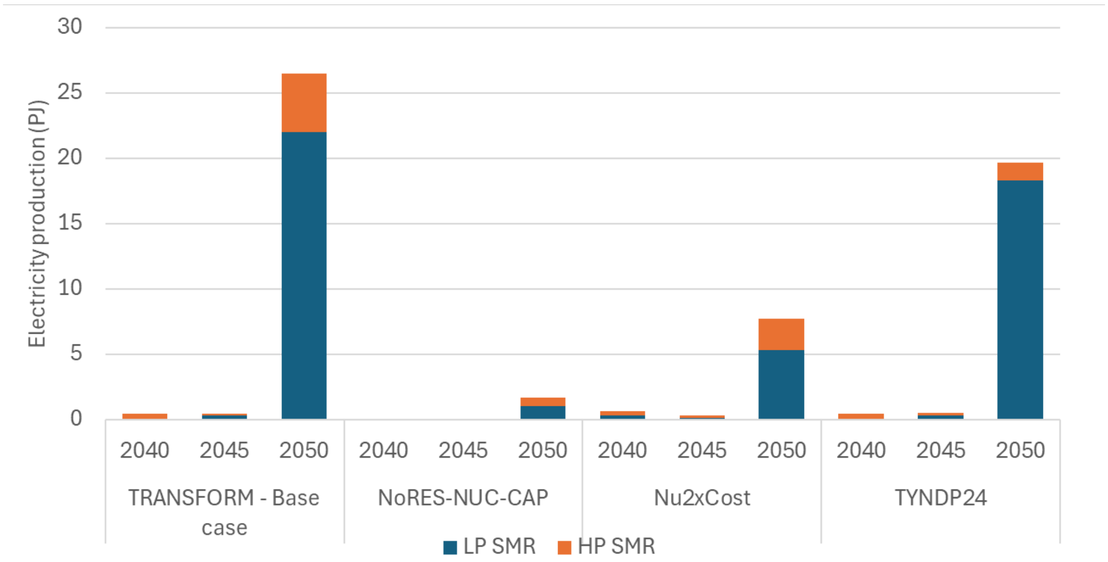



Figure 3.20: Electricity production from SMRs in the base case TRANSFORM and the what if scenarios

*SMR heat supply*

Figure 3.21 shows the heat supplied in PJ by the SMRs in the base case TRANSFORM scenario and the what if scenarios. This shows that in 2050 there is slightly less total heat production in all what if scenarios compared to the base case. The drop seen in heat production is significantly less as a proportion of the total than for electricity. This indicates that the SMRs are playing a key role in all the scenarios for heat production that is more costly for other energy sources to take over. The HP SMR heat production is most similar between the base case TRANSFORM scenario and NoRES-NUC-CAP scenario. This indicates that the higher temperature range (200-400 °C) is harder to replace with electricity from RES. The reduction in total heat supplied by SMRs in the Nu2xCost scenario is almost entirely due to the reduction in supply from the HP SMRs, indicating that this temperature range is more sensitive to increases in cost. Figure 3.22 shows the proportion of heat in the different categories coming from SMRs. As with the total heat production in Figure 3.21, the proportion of heat coming from SMRs decreases in the what if scenarios compared to the base case. However, in all scenarios for both temperature ranges the SMRs still provide more than half of the heat and are always in 2050 the technology providing the largest amount of heat.

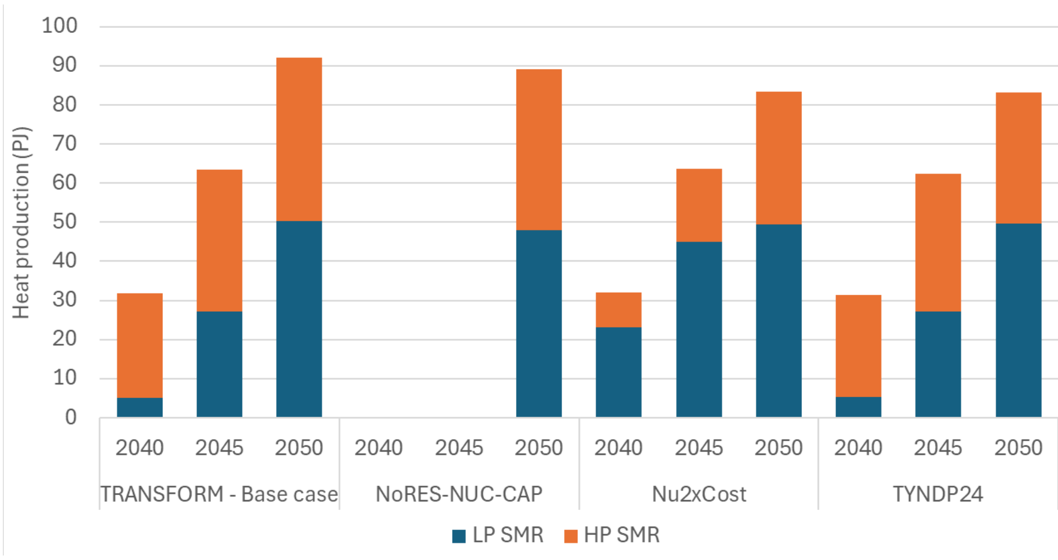



Figure 3.21: Heat production from SMRs in PJ in the base case TRANSFORM and the what if scenarios

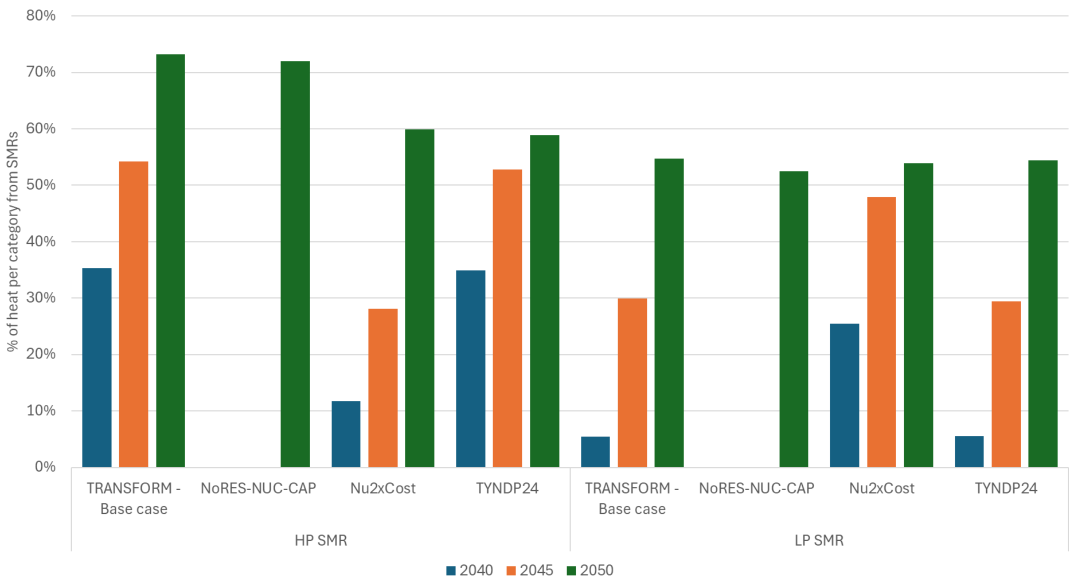



Figure 3.22: Proportion of total heat demand supplied by SMRs in the base case TRANSFORM and the what if scenarios

The heat demand in both the 100-200 °C and the 200-400 °C categories are shown in Figure 3.23 and Figure 3.24. Heat demand in the 200-400 °C category is very stable in 2050 between all the what if scenarios. This stability in the heat demand is interesting as even with increases in the cost of heat, such as in the Nu2xCost scenario, there is not a large decrease in demand. The SMRs still make up the largest heat supply route and the amount of heat they provide is reasonably similar. Additionally, the second largest supply route for this temperature of heat is still waste gas boilers of various kinds. The largest difference in heat demand between the base case TRANSFORM and the NoRES-NUC-CAP scenario is the location of this demand. For example in the base case TRANSFORM scenario the heat demand is more focused in South Holland with approximately 21 PJ of heat demand for aromatics here, and 17 PJ of heat demand for other refinery demand. In the NoRES-NUC-

CAP this heat demand shifts more towards Zeeland with it taking 17.2 PJ of heat demand for the aromatics production and South Holland only 11.6 PJ. However, the overall national demand is very similar between the two cases. For the Nu2xCost scenario the heat demand and supply is very similar to the base case. Examining the 100-200 °C shows a similar situation as the 200-400 °C, the change of total heat demand between 'what if' scenarios is very small. For the 100-200 °C category the heat demand is mainly focused on the chemicals industry in all scenarios.

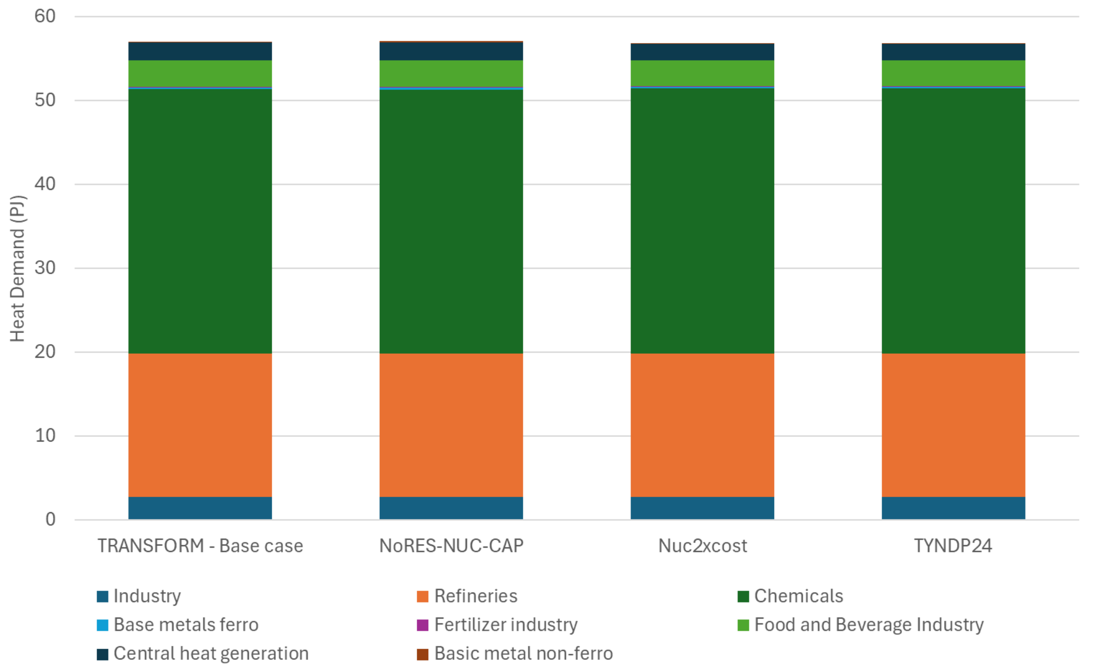



Figure 3.23: Heat demand in the 200-400 °C by sector in the base case TRANSFORM and the what if scenarios in 2050

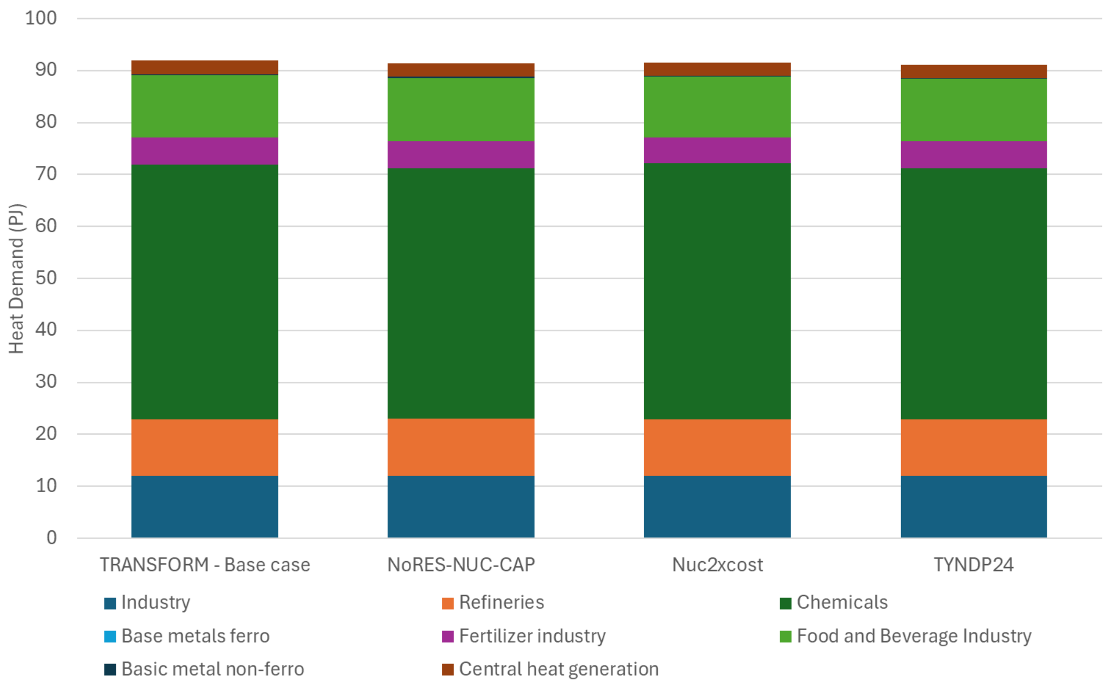



Figure 3.24: Heat in the 100-200 °C category by sector for base case TRANSFORM and the what if scenarios in 2050

# 3.4 Discussion

## 3.4.1 Limitations of the integrated energy system analysis

Research into the integration of nuclear energy using cost-optimization models such as OPERA has several limitations:

- Cost optimisation models generate target scenarios in which the energy system meets predefined objectives and constraints. This assumes that technologies are available on time, can be scaled up effectively, and are adopted by citizens and businesses. In reality, such assumptions often face challenges: technologies may not yet be mature or scalable, business cases may be unviable, risks may be too high, grid expansion may be delayed, funding may be insufficient, and skilled labour may be lacking (Andres, Scheepers, Van den Brink, & Smokers, 2022). Although models attempt to account for some of these limitations – such as by imposing deployment limitations – the risk is that they present an optimistic view of how quickly the energy system can transform. To better assess the feasibility of current policy goals and explore alternative transition pathways, additional research into the practical barriers to the energy transition is essential. Such research can enhance understanding of real-world constraints and inform more realistic and effective strategies.
- Although the OPERA model offers a highly detailed representation of the energy system, it remains a simplified reflection of reality. For instance, the model incorporates only a limited grid topology of the electricity infrastructure. As a result, the impact of nuclear energy on the grid can currently be assessed only to a limited extent (Kooiman, Scheepers, Beres, Hakvoort, & Meeuwsen, 2025). A more thorough analysis would require modifications to the model.

- The present study uses two scenarios (ADAPT and TRANSFORM) to account for uncertainties in the development of the future energy system. In addition, various input parameters are estimated (see Section 2.3). Sensitivity and what-if analyses are conducted to explore the impact of certain assumptions, such as the costs of nuclear power plants (NPPs). Other plausible scenarios, such as those involving lower future energy demand from energy-intensive industries or higher imports of biomass, biofuels and/or synthetic fuels, are not explored in depth in this study. Research by (Scheepers, et al., 2024) indicates that reduced industrial energy demand can significantly influence the cost-optimal capacity of both large NPPs and small modular reactors (SMRs). Also the cost-optimal deployment of nuclear energy is sensitive to assumptions about, among others, the costs of electricity infrastructure, electrolysers, and flexibility options, as examined in (Kooiman, Scheepers, Beres, Hakvoort, & Meeuwsen, 2025). These other studies underscore the importance of broadening scenario analysis to better understand the full range of possible outcomes and system configurations.
- Cost optimization applied is the present study aims to minimize the social costs of the energy system. This includes the financial benefits of avoided costs within the system itself. However, it does not account for broader impacts of the energy transition that fall outside the energy system. For instance, indirect effects – such as shifts in economic sectors or the development of new market dynamics – are excluded. Non-financial factors are also disregarded. If these externalities were considered, the socially optimal outcome could differ.

### 3.4.2 Limitations of in relation to SMRs

The modelling of the SMRs in this system requires some assumptions and simplifications regarding how SMRs work and how they provide industrial heat and electricity. Firstly, the SMRs in this study are based on a generalized light water reactor design that is able to provide both heat and electricity. Most light water reactors are only able to operate with core exit temperatures of around 300 °C, meaning that they cannot generate steam at higher temperatures than this. They are assumed in this study to operate in the 200 - 400 °C temperature range. This is a necessary assumption for the model but in reality a mixture of different SMR technologies will need to be deployed, including advanced modular reactors based on technologies such as molten salt technology and gas cooled reactors, to meet the heat demand in this temperature category.

Additionally, the regional allocation of SMR capacity is challenging due to the non-discrete way that the power sources are modelled meaning that the capacities of SMRs per region do not always align well with realistic SMR deployment scenarios. While this is true for all power sources, other power sources are less impacted due to having smaller unit sizes or a wider range of power per unit available in the market. This is the reason that the 50 MW cut-off was implemented, with any region having below 50 MW of capacity being removed from the regional analysis. Changing the way that the SMR capacity is allocated and allowing this discarded capacity to be allocated to other regions would provide a more complete understanding of how SMRs are likely to be used.

Lastly, the range of conditions for the what if scenarios provide a broad understanding of how SMRs work. However, for the ADAPT base case scenario the maximum national SMR capacity is reached in all years. While this value each year may be the optimal for the system, it is also possible that it would have been more economically optimal for the system to allocate extra SMR capacity if this constraint was not active.

Currently in this study SMR capacity limits are only removed at the same time as the limits placed on the capacities for wind and solar-PV and only for the TRANSFORM scenario. Future studies should consider allowing SMR capacity to be unconstrained – while wind and solar-PV potentials remains limited – to understand how this would impact the wider system as well as the SMR deployment.

# 4 Nuclear energy in the energy market

In the previous chapter, the role of nuclear has been explored from an integrated national energy system perspective by means of the OPERA model. Whereas OPERA offers a highly detailed representation of the Dutch energy system, it cannot provide relevant insights on the potential role of nuclear in the Netherlands in the context of a European energy market in which the Netherlands is highly interconnected with neighbouring countries. Thus, in order to complement these findings, an additional analysis is performed to delve into the role of nuclear in the Netherlands from a European energy market perspective, investigating the potential effects abroad of Dutch nuclear expansion.

This chapter is structured as follows: firstly, (Section 4.1) introduces the correspondent relevant research questions, as well as the approach followed by using the COMPETES-TNO model to answer them; secondly, (Section 4.2) provides the main results; and finally, (Section 4.3) provides a discussion of the results and the policy implications for nuclear in an energy only market (EOM).

## 4.1 Introduction

The Netherlands is connected to the extensive European power network with interconnections with surrounding countries such as Germany, Belgium, UK, Norway and Denmark. In addition, the Dutch energy system is expected to be connected internationally via hydrogen pipelines, notably with Germany, Belgium, UK and Norway[19]. This means that changes within individual countries through these interconnections may impact the operation of surrounding (and potentially beyond) energy systems. These changes can be associated to developments in electricity or hydrogen demands, differences in the generation mix, among others. These dynamics can be explored utilizing the power market COMPETES-TNO model (see Section 2.1.2 for the model's detailed description).

For the purpose of the present study, the role of nuclear integration in the Dutch power system is explored to provide insights on the following research questions as stated previously in 1.2:

5. What is the impact of nuclear integration on the need for flexibility in the electricity system?
6. What are the consequences of nuclear integration on energy market prices?
7. How will NPPs be operated in the future electricity market, what limits the flexible operation of nuclear reactors and how can social and private (i.e. investor) costs and benefits be balanced?

The approach for this analysis is based on the free optimization of the power and flexible capacities of the Netherlands and the rest of European countries using COMPETES-TNO. The workflow is as follows:

[19] Based on retrofit of existing gas infrastructure.

- The domestic electricity and hydrogen demand of 2040 and 2050 in the Baseline hourly results from OPERA serves as input for COMPETES-TNO for both ADAPT and TRANSFORM for the Netherlands, with the rest of countries based on the TYNDP-22 DE scenario demand assumptions (see 2.2).
- The initial power and flexible capacities of the Netherlands in 2030 in the Baseline hourly results from OPERA serve as initial capacities for the optimization of COMPETES-TNO for ADAPT and TRANSFORM.
- COMPETES-TNO optimizes the generation and flexible capacities according to this boundary conditions the Dutch power system for 2040 and 2050.

As discussed previously in Box 2, COMPETES-TNO and OPERA optimize different goals, and have different geographical scopes, which can cause disparity on the outcomes. The optimization of COMPETES-TNO shows that, despite having the same electricity and hydrogen demands as in the Baseline of OPERA, no further investments in nuclear occur in the Netherlands in either of the scenarios. Outside of the Netherlands, additional nuclear capacities are also not found optimal by the model given the assumed techno-economic parameters.

However, in order to explore the effect of nuclear, a comparison against a system with nuclear is necessary. To address this, the nuclear capacities for the Netherlands, resulting from the Baseline hourly results from OPERA (Table 4.1), are exogenously defined in COMPETES-TNO for both ADAPT and TRANSFORM. These capacities comprises both large NPPs and SMRs. Given that COMPETES-TNO is inherently a power market-based model, there is a lack of representation of the heat sector, and therefore the co-generation capabilities of SMRs are disregarded, thus its operation rely purely on electricity generation. Due to this, the following analysis with COMPETES-TNO in this chapter focuses solely on large NPPs. However, SMR production capacity is included in the results, with SMRs exhibiting the same behavior as large NPPs.

Table 4.1: Nuclear installed capacities in the Netherlands for the Baseline case.

| [GWe] | ADAPT | | TRANSFORM | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Nuclear large | 1.2 | 6 | 3.5 | 6 |
| Nuclear SMR | 0.45 | 2.1 | 0.45 | 2 |

With this, two sets of results from the COMPETES-TNO optimization are obtained for the years 2040 and 2050 for each scenario (Figure 4.1):

- **Baseline:** exogenously defined new Dutch nuclear capacities based on the hourly Baseline results from OPERA.
- **NoNuclear**: no new Dutch nuclear capacity between 2040 and 2050. All existing nuclear capacity in the Netherlands and abroad remains.

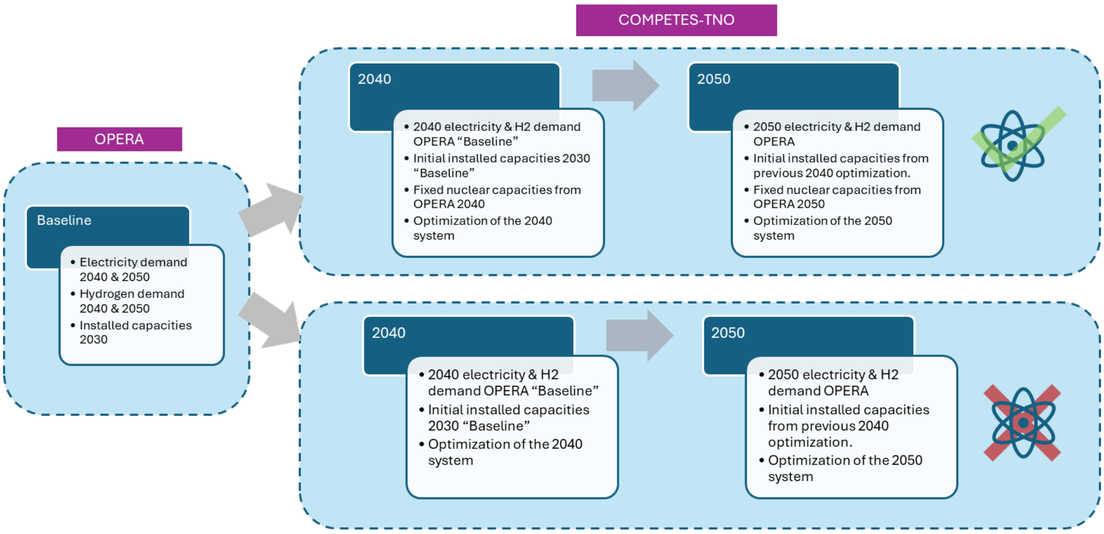



Figure 4.1: Approach modelling for the COMPETES-TNO analysis.

# 4.2 Results

This section presents the results of the optimization of COMPETES-TNO for both the Baseline and NoNuclear cases, for the Netherlands and also for selected surrounding countries to explore the effect abroad of potential nuclear expansion in the Dutch power system.

## 4.2.1 Electricity demand

As explained previously, the Netherlands' electricity demand for COMPETES-TNO is exogenously determined based on the Baseline of OPERA hourly results, for both analysed cases. Figure 4.2 shows the electricity demand for the Baseline as well as differences corresponding to the flexible demands optimized by the model under the Baseline and NoNuclear cases (in following graphs the results are presented in the same way). The comparison shows that the most sensitive type of demand is electrolysis to produce green hydrogen (P2H2). Under NoNuclear, a reduction of 28 and 34 TWh of electrolysis is observed compared to the Baseline for ADAPT and TRANSFORM respectively.

This P2H2 demand is highly sensitive to electricity prices, as the model optimizes the production of electrolysers based on these. The domestic $H_2$ production is in competition with other sources, such as steam methane reforming or imports. When electricity prices rise above the costs of these other sources, the production of electrolysis decreases. The effect on electricity prices will be explored in more detail in Section 4.2.4.

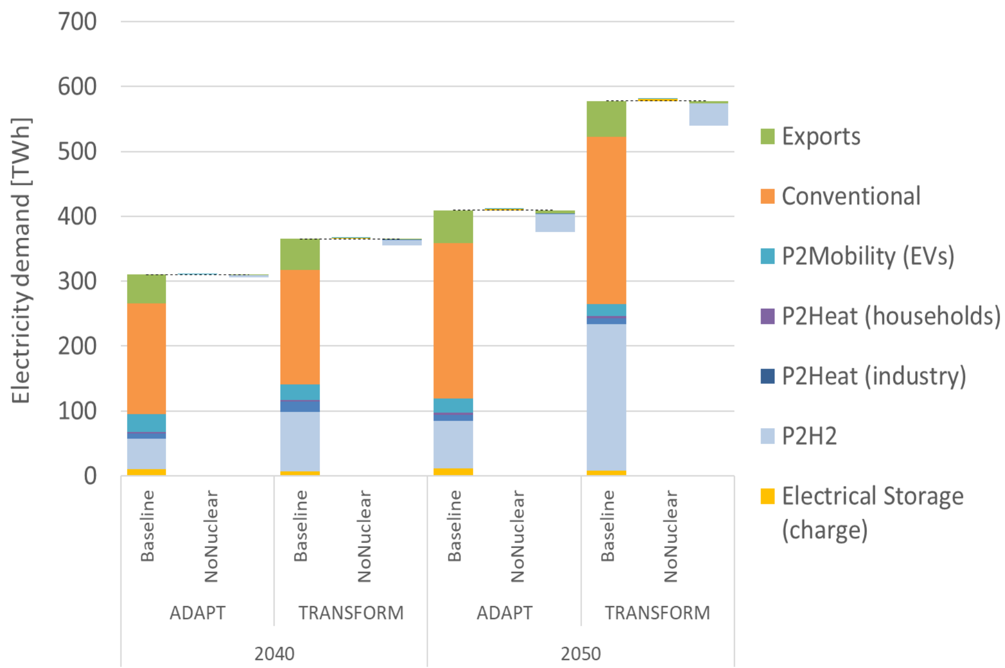



Figure 4.2: Electricity demand in the Netherlands for ADAPT and TRANSFORM for the two cases in 2040 and 2050.

Electricity trade is also quite price sensitive, with a slight decrease of exports under the NoNuclear compared to the Baseline of 5 and 4 TWh less in ADAPT and TRANSFORM respectively in 2050. The effects on trade will be explored in more detail in Section **4.2.6**. Other flexible demands, such as the charging of batteries increase marginally in both scenarios under NoNuclear. These effects of nuclear on flexible electricity demand follow a similar trend as the one observed previously in the OPERA analysis.

Figure 4.3 shows the changes in the electricity demand for some key surrounding countries: Germany (DE), Belgium (BE), and the UK for the year 2050, when more nuclear capacity is installed in the Netherlands. However, the effects observed in the three countries when comparing the baseline situation with NoNuclear are insignificant. The results demonstrate the important role P2H2 plays in the UK in balancing the large share of offshore wind production. Germany, despite a considerable hydrogen demand, relies more on $H_2$ imports from other countries, similar for Belgium, to supply its demand, as will be explored further in Section **4.2.6**. Overall, the effects on the demand from abroad due to nuclear in the Netherlands are minimal.

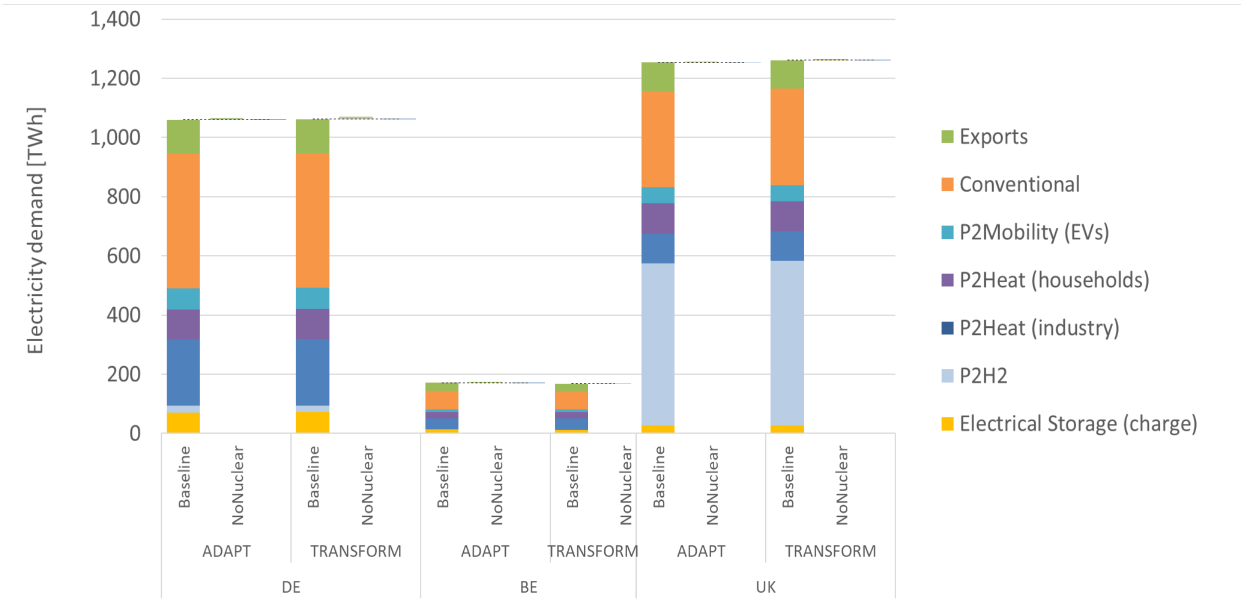



Figure 4.3: Electricity demand for Germany, Belgium, and the UK for ADAPT and TRANSFORM for the two cases in 2050.

## 4.2.2 Installed generation capacities

Figure 4.4 shows the installed generation capacities for the Netherlands under the Baseline case and NoNuclear case for TRANSFORM and ADAPT. Both scenarios start with the corresponding installed capacities from 2030 by OPERA, and then optimize according to the respective electricity and hydrogen demands for each following scenario year by COMPETES-TNO. Both scenarios share the same VRE potentials as OPERA. In the both Baseline and NoNuclear the maximum potential for wind offshore and wind onshore are reached in 2050. In the COMPETES-TNO model results solar PV is deployed to a lower extent than in the OPERA results, with installed capacities of 62 and 73 GW in 2050 for ADAPT and TRANSFORM, respectively.

In NoNuclear the nuclear capacity is mainly replaced by solar PV, with an additional 18 and 20 GW installed in 2050 for ADAPT and TRANSFORM. An additional effect that can be observed is the need for gas-fired units in the mix. Under ADAPT, the Baseline is completely gas-free, as all gas-fired units are decommissioned by the model. On the other hand, under NoNuclear, around 3 GW of gas-fired capacity remains in the system. A similar trend occurs for TRANSFORM, as an additional 4 GW remain on top of the 7.5 GW in the Baseline. The operation of these gas units is purely back-up, with extremely low full-load hours.

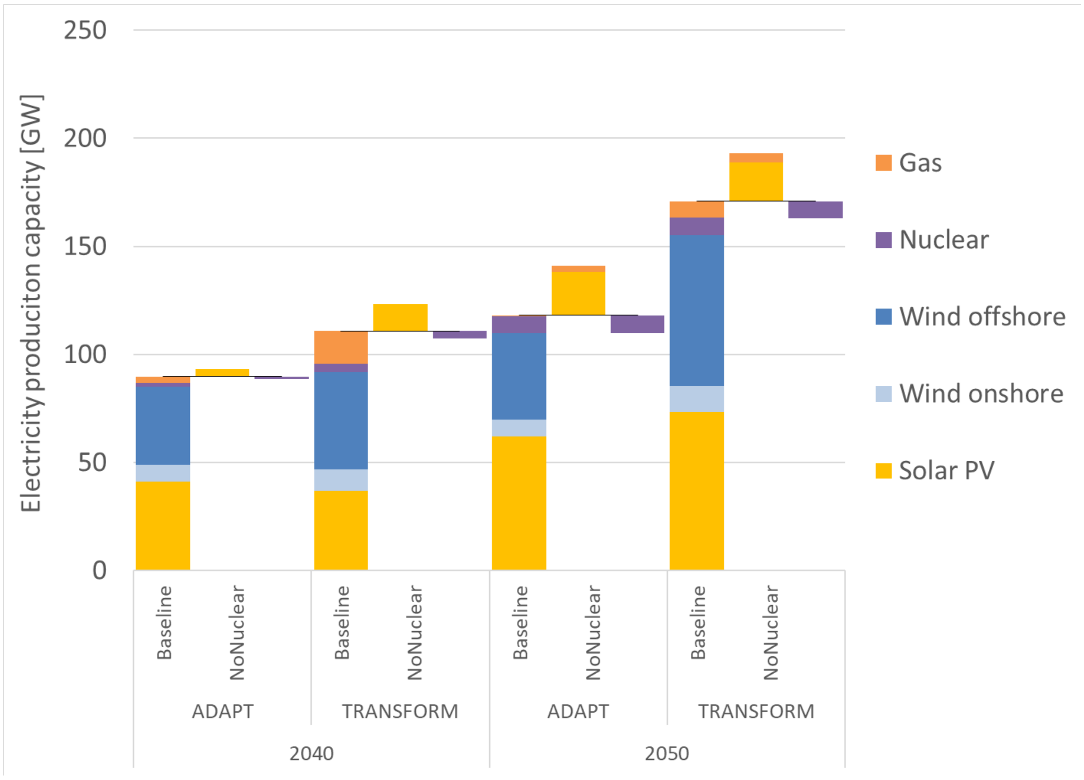



Figure 4.4: Installed capacities of generation technologies in the Netherlands for ADAPT and TRANSFORM for both cases in 2040 and 2050

Effects for surrounding countries remain negligible (see Figure 4.5), with similar trends as the ones observed in the Netherlands, with an increase of solar PV installations and lower decommissioning of gas-fired units, notably in Germany and Belgium.

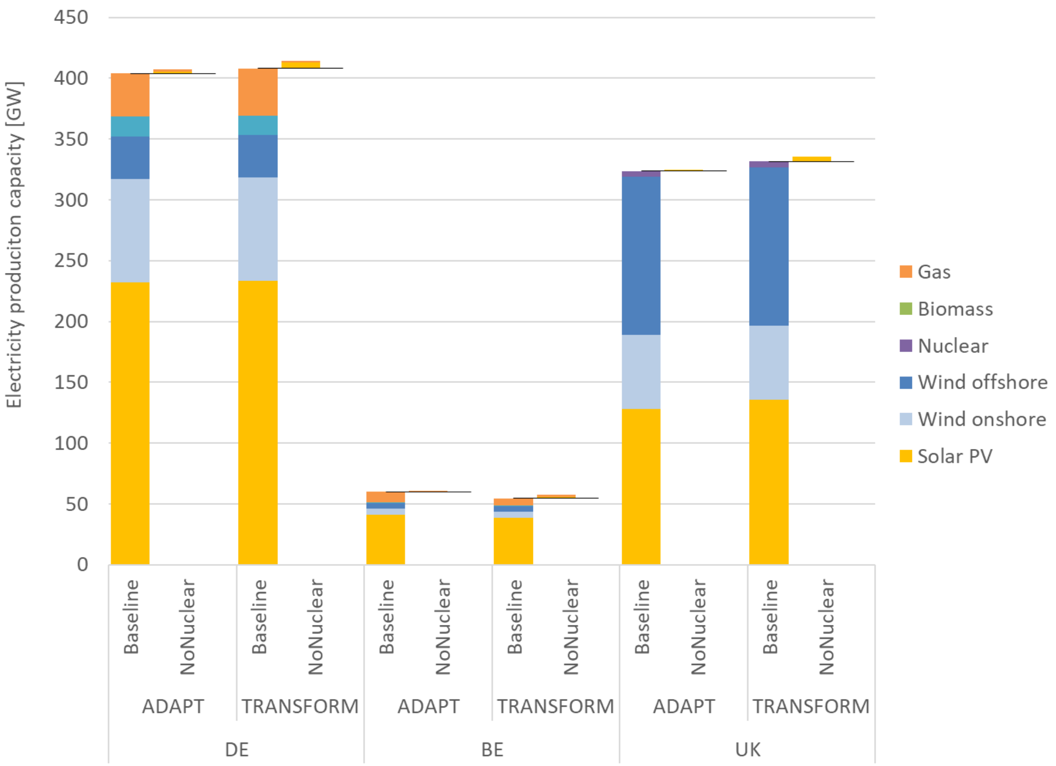



Figure 4.5: Installed capacities of generation technologies in Germany, Belgium and the UK for ADAPT and TRANSFORM for both cases in 2050.

## 4.2.3 Electricity supply

Figure 4.6 shows the Netherlands electricity supply mix for the Baseline and the differences under NoNuclear. The exclusion of nuclear generation in the Baseline in 2050, of around 40 TWh from large NPPs in both scenarios and 13 TWh from SMRs in 2050, is only partially covered by an increase of solar PV generation, of 20 and 18 TWh in ADAPT and TRANSFORM respectively. Overall, a net decrease in power generation is observed as a result of the lower electricity demand from conversion technologies mentioned previously.

The nuclear generation of Baseline in 2050 is also partially replaced by an increase in imports, in the order of 5 and 4 TWh in 2050 for ADAPT and TRANSFORM, respectively. Interestingly, under NoNuclear a decrease of wind offshore output is also observed. This is explained by an increase in curtailment of wind offshore driven by the higher output of solar PV in the mix.

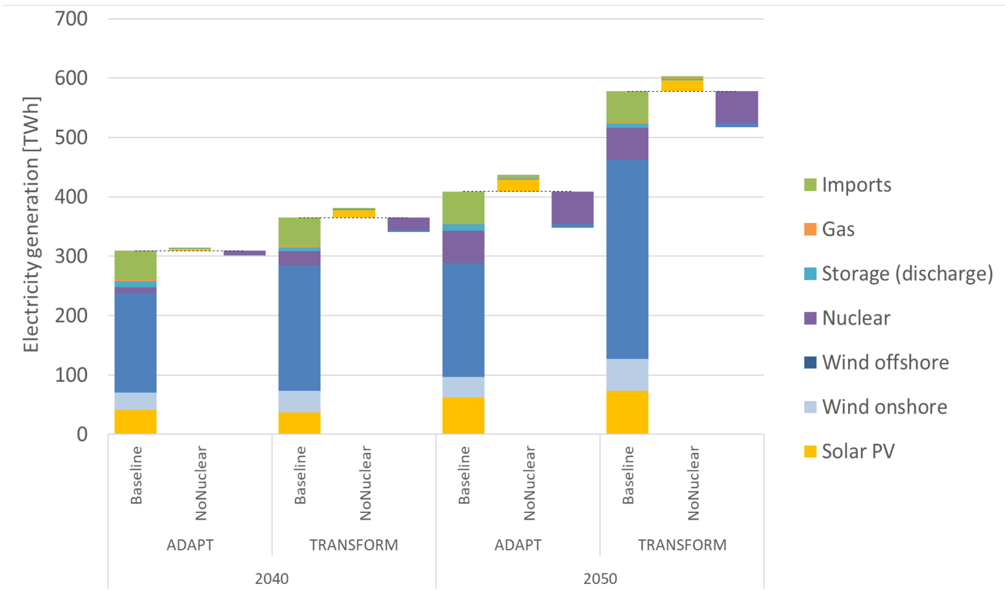
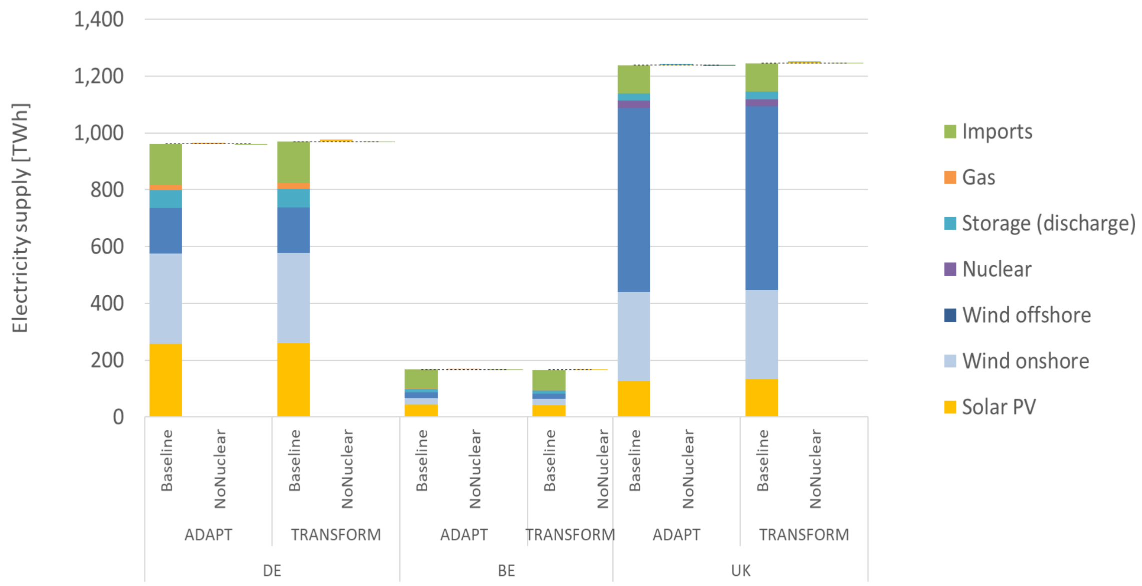



Figure 4.6: Electricity supply for the Netherlands in ADAPT and TRANSFORM for the two cases in 2040 and 2050.

Although the changes in the supply mix in the Netherlands are relatively meaningful, surrounding countries are not affected significantly. Figure 4.7 displays the differences between the Baseline and NoNuclear cases for DE, BE and UK in 2050. The effects between both cases are negligible, similar to the low effects also observed regarding the electricity demand. A closer look at the small variations observed indicates that solar PV is again the most sensitive technology for the exclusion of nuclear, with the correspondent decrease of wind output. A common trend is the (marginal) decrease of imports. As the Netherlands reduces the supply of electricity from NPPs, neighboring countries also reduce imports from the Netherlands. As a result, an increase in dispatchable capacity is observed (primary in Germany and Belgium), mainly from gas-fired units.



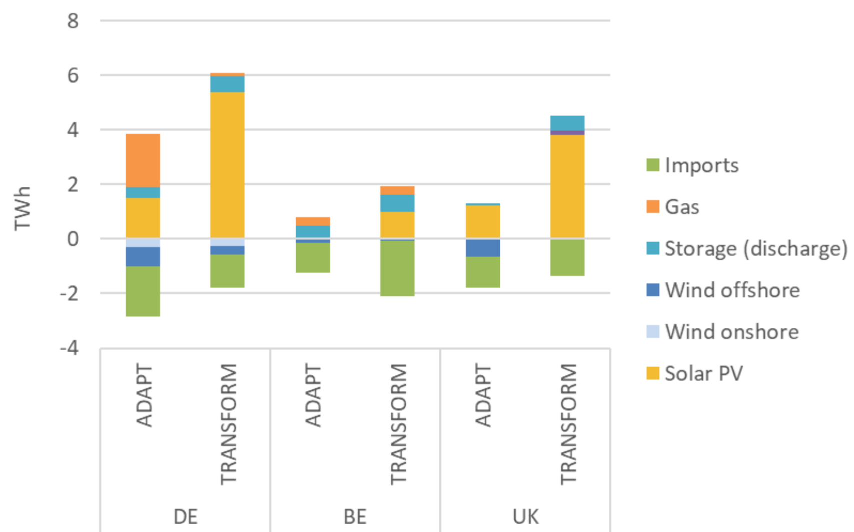
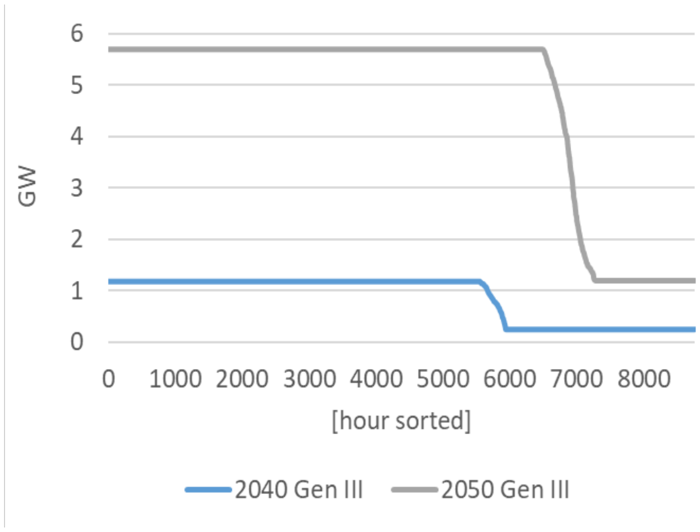




Figure 4.7: Electricity supply for Germany, Belgium and the UK in ADAPT and TRANSFORM for the two cases in 2050 (above). Zoom in the changes in electricity supply for those countries (below).

As part of the generation mix in the Baseline, NPPs provide a considerable portion of the domestic supply. NPPs are known to provide baseload power, resulting in high capacity factors and full load hours (FLHs). The nature of this operation is mainly due to the economic characteristics of this technology. With high investment but low operational costs, NPPs operate for long time periods, with few shut-down times for maintenance and nuclear fuel replacement. The evolution towards systems with high shares of VRE calls for nuclear to behave as a load-following technology. This is the type of operation observed in COMPETES-TNO (see Figure 4.8), where in 2040 large NPPs operate for about 5,500 hours in the years, increasing to 6,500 hours in 2050. The operation of existing nuclear capacity in other countries, like in the UK and France is not affected meaningfully by the presence of additional nuclear capacity in the Dutch power system.



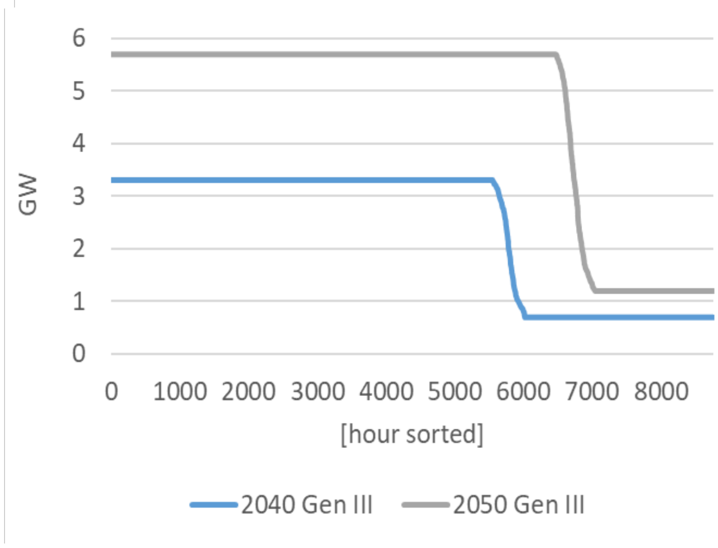




Figure 4.8: Duration curves of large NPPs in the Netherlands in the Baseline scenario with ADAPT (above) and TRANSFORM (below) in 2040 and 2050.

As described previously in Section 2.3.4, NPPs are able to be fully flexible on an hourly scale, as the ramp rate for this technology is assumed to be 5% per minute. There are other limitations such as maintaining a minimum load of 20% the rated capacity. These considerations are represented in the modelling for nuclear in the COMPETES-TNO model. However, other conditions, such as the number of fuel cycles or the minimum up/down times are not explicitly modelled. Instead, this has been monitored to compare the feasibility of the operation of large NPPs in the model versus what would be expected in reality. The monitoring results are summarized in Table 4.2 The benchmark figures for the maximum cycle counts of nuclear is estimated to be around 200 cycles per year to be capable to do load-following, and when production ramps down to 20% of the minimum load, a time period of 6 consecutive hours is required before increase in output can take place again to deal with Xenon poisoning[20]. The results show that the number of cycles for

[20] Xenon poisoning in nuclear reactors refers to the reduced reactivity caused by the buildup of xenon-135, a fission product, and a strong neutron absorber, within the reactor core. Xenon-135 absorbs neutrons, effectively "poisoning" the reactor by reducing the number of neutrons available for sustaining the nuclear chain reaction.

large NPPs is around 100-130 per year, and that between 10 and 40 times a year the minimum 6 hours downtime is not accomplished.

Table 4.2: Resulting operation parameters for large NPPs in COMPETES-TNO Baseline cases.

| | ADAPT | | TRANSFORM | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | T2050 |
| Number cycles (#/year) | 104 | 104 | 102 | 128 |
| Minimum down time violation (#/year) | 13 | 20 | 20 | 41 |

To explore further the load-following operation of nuclear in the context of a high-VRE system, operational patterns from nuclear, wind and solar PV is presented in Figure 4.9 in the form of heat maps. The top graph shows the operation patterns of large NPPs for Baseline TRANSFORM 2050, where the vertical axis represents the hours of the day and the horizontal axis the days of the year. The periods displayed in red color indicate that nuclear operation is above the minimum load, and the green periods nuclear is operating at minimum load.

Similarly, the middle and bottom heat maps show the generation from wind (onshore and offshore) and solar PV, respectively, where red periods indicate maximum output of the technologies, and green output indicate minimum output (i.e. not generation at all). In the case of the VRE profiles, we can observe the expected lower generation of solar PV during winter months and its increase during summer. This pattern is partially complemented by the generation from wind, which is more prominent during winter.

The pattern of nuclear generation shows that minimum load operation occurs in those periods where VRE is highly available, notably wind. This can be seen on the last days of the year (350-365), where wind production is extremely high. During the period 250-300, the opposite occurs: nuclear operation is at full capacity to compensate for lower electricity production from wind.

Therefore, in a highly VRE-based power system, nuclear generation with load following capabilities can effectively complement the VRE generation patterns, covering the positive residual load of the system[21]. This is a different behaviour than what we saw in the OPERA results. Instead of optimizing for revenues from electricity production, OPERA allows NPPs to operate in a baseload mode because this leads to a more cost-efficient outcome for the entire energy system. The flexibility provided by large NPPs in the COMPETES-TNO model can lead to competition with other generation technologies and flexible assets that help to balance the supply and demand of the power system. This effect is analysed in more detail in Section 4.2.5.

[21] The residual load is defined as the domestic electricity load minus the production of VRE before curtailment.

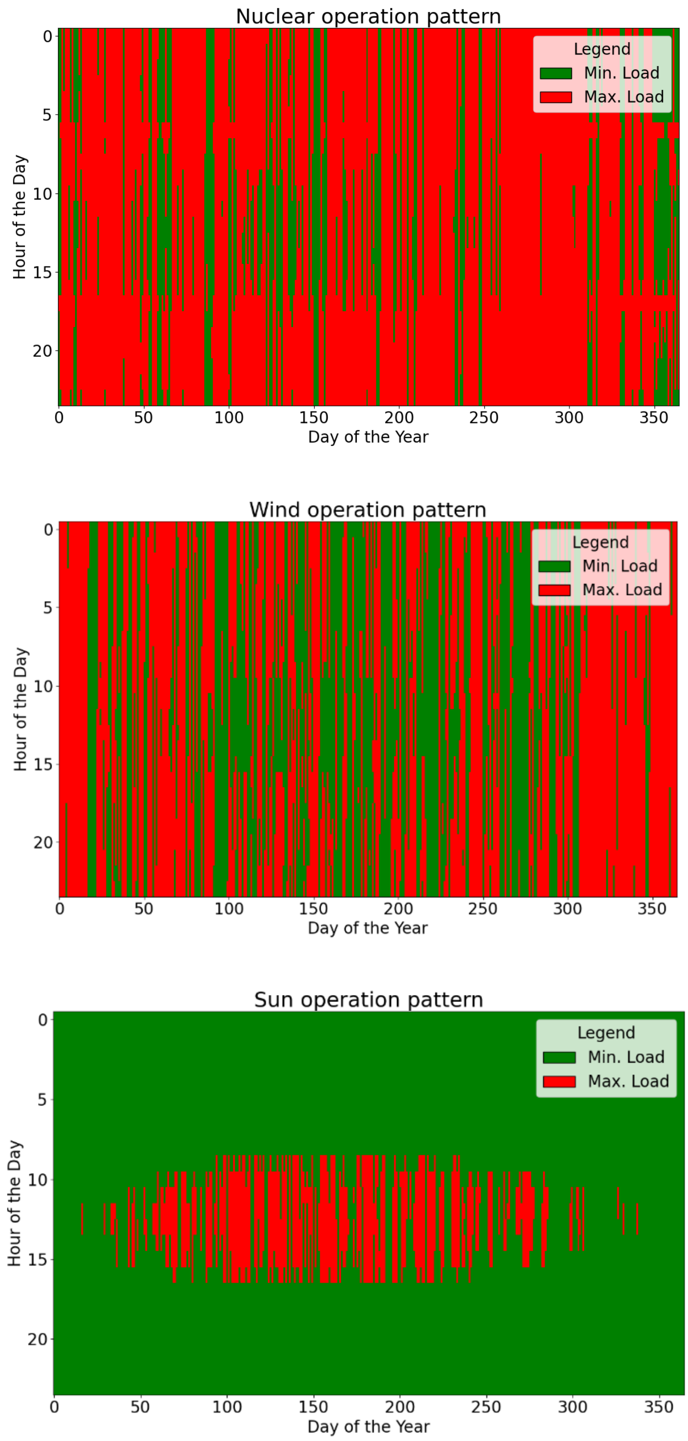



Figure 4.9: Pattern operation for Baseline TRANSFORM 2050 large NPPs (above), wind onshore and offshore (middle) and solar PV (below) during the year presented as a heat map.

## 4.2.4 Prices

Changes in supply and demand affect the electricity and hydrogen prices. Figure 4.10 shows the electricity price duration curve for ADAPT and TRANSFORM for both the Baseline and NoNuclear cases for the Netherlands, expressed in Euros 2015. Overall, Baseline cases show lower electricity prices than NoNuclear. This can be explained by the fact that nuclear energy is a relatively low marginal cost unit and thus makes it possible to displace higher cost units (such as gas-fired units) from the system.

Table 4.3 summarizes the electricity Weighted Average Market Prices (WAMP)[22] for the different cases and scenarios. The 'price-depressing' effect of nuclear energy is particularly evident in the ADAPT 2050 scenario. Under the Baseline case, the introduction of nuclear leads to the complete phase-out of gas-fired units, which in turn significantly reduces domestic electricity prices in the Netherlands by an average of €8.8/MWh.

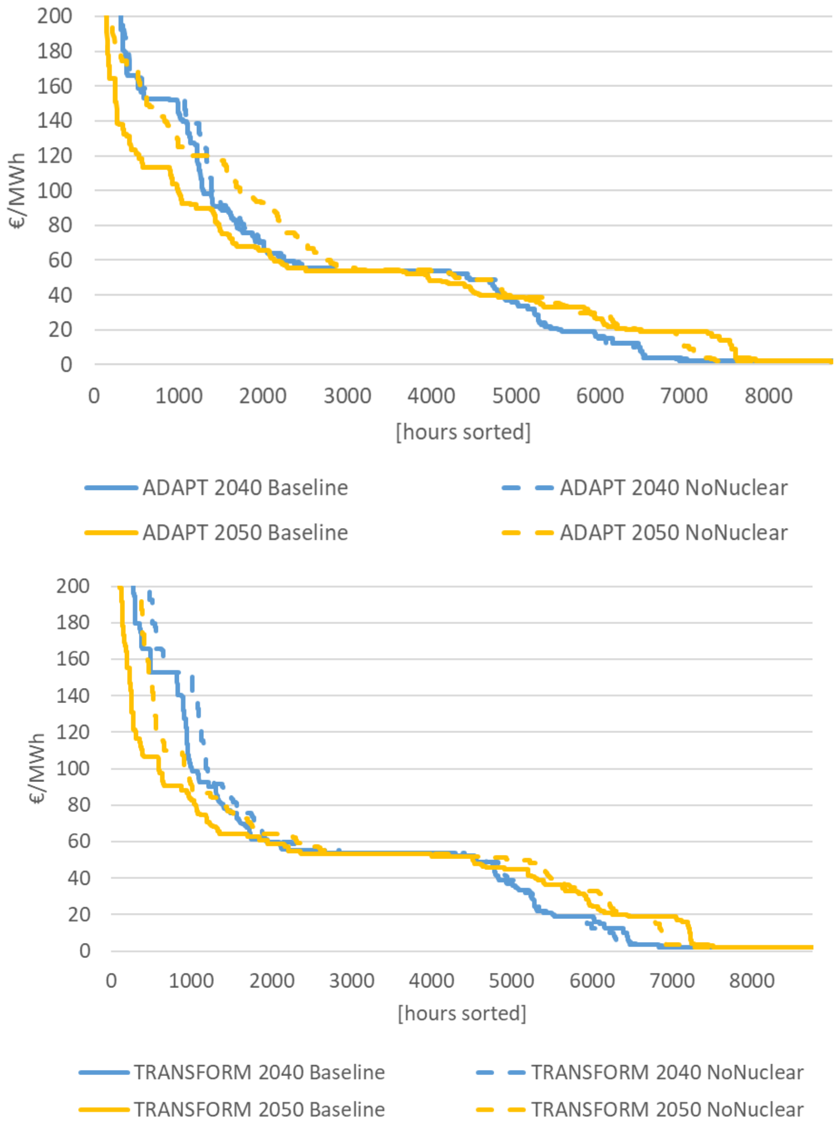



Figure 4.10: Price (in $€_{2015}$) duration curves for electricity prices in Netherlands for both analysed cases for ADAPT (above) and TRANSFORM (below).

[22] WAMP is the volume-weighted average of the electricity prices considering the electricity demand.

Table 4.3: WAMP electricity prices for the Netherlands under the different cases and scenarios optimized by COMPETES-TNO

| [€2015/MWh] | ADAPT | | TRANSFORM | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Baseline | 47.9 | 45.1 | 42.3 | 39.3 |
| NoNuclear | 48.9 | 53.9 | 44.9 | 42.7 |

For surrounding countries like Germany, Belgium and the UK, Figure 4.11 shows the electricity WAMP for the year 2050 in both ADAPT and TRANSFORM scenarios. A similar trend is observed in these countries, where electricity prices in the NoNuclear scenarios are consistently higher than in the Baseline. This is largely due to the integration of Dutch NPPs into the system, which contributes to lowering overall electricity costs.

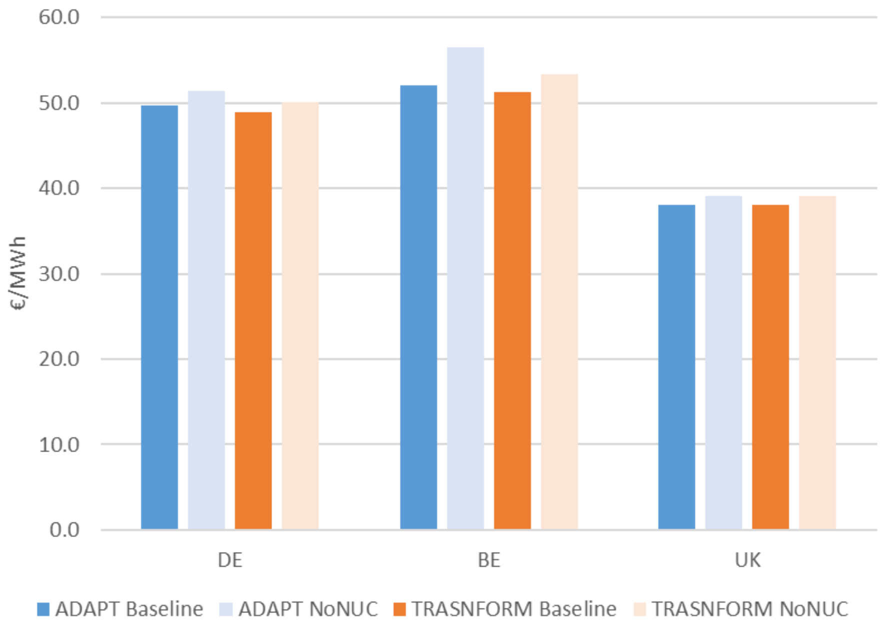



Figure 4.11: Electricity WAMP (in €2015) for Germany, Belgium, and the UK in 2050.

Hydrogen prices are highly correlated to electricity prices due to the electrolysis process, where the efficiency of the electrolyser play an important role. Hydrogen is mainly produced by electrolysis in 2040 and 2050 across Europe, with some small remaining steam methane reforming with CCS capacity. Besides, the imports and exports of hydrogen between countries, as well as $H_2$ storage in the form of salt caverns can provide flexibility to fulfill domestic hydrogen demand.

In the case of the Netherlands, as can be observed in Figure 4.12, hydrogen prices remain quite stable through the year, with may hours but not all on the 2.8 €/kg level. The hydrogen prices from COMPETES-TNO are the result of a six-hour balance, so to obtain a full year profile, the same price for every six hour block is assumed. Although the divergence between Baseline and NoNuclear cases is quite noticeable for the electricity prices, this effect is lower for hydrogen. Table 4.4 summarizes the $H_2$ WAMP for the Netherlands, where under NoNuclear marginal higher $H_2$ prices compared to the Baseline occur. Given the $H_2$ trade between countries, hydrogen prices are quite stable as the model invests electrolysis capacity in countries with low electricity prices and allows exports to meet foreign hydrogen demand. In this COMPETES-TNO analysis the Netherlands is a net importer of $H_2$, and therefore benefit from this trade, and as changes abroad with additional NPs are not significant, the second order effect on hydrogen prices are not that significant across cases.

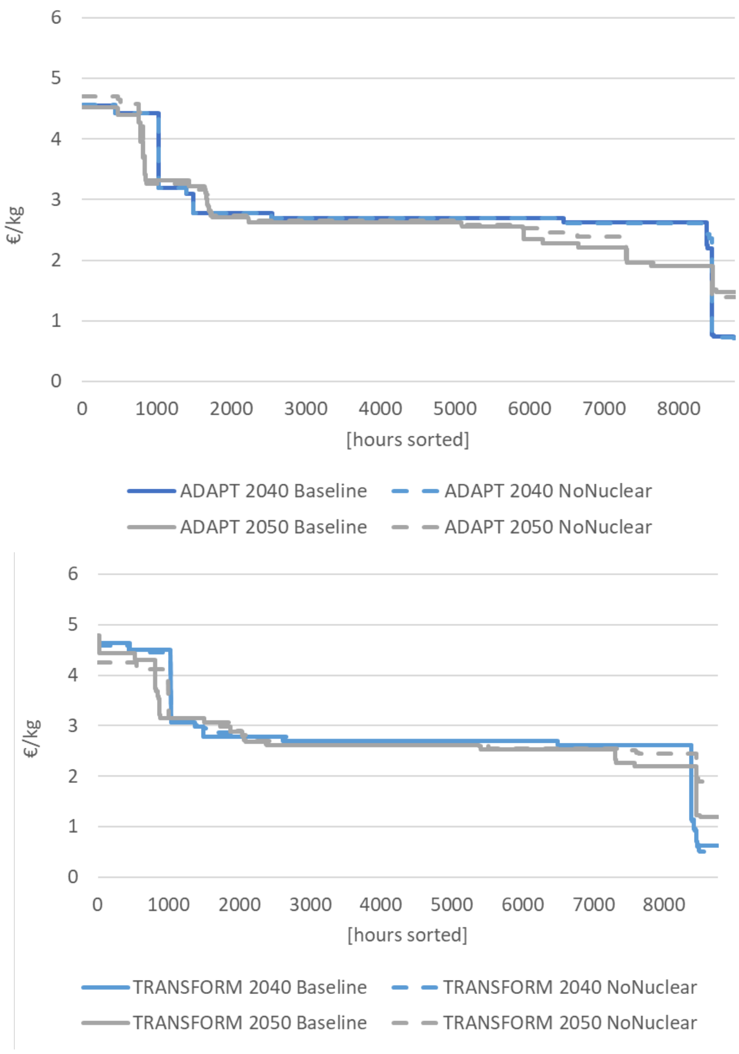



Figure 4.12: Price duration curves (in $€_{2015}$) for hydrogen in the Netherlands for ADAPT (above) and TRANSFORM (below).

Table 4.4: WAMP hydrogen prices for the Netherlands under the different cases and scenarios optimized by COMPETES-TNO.

| [€$_{2015}$/kg $H_2$] | ADAPT | | TRANSFORM | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Baseline | 2.8 | 2.6 | 2.8 | 2.7 |
| NoNuclear | 2.8 | 2.7 | 2.8 | 2.8 |

For surrounding countries in 2050, the hydrogen WAMP also shows a slight increase under the NoNuclear case, but effects are negligible (see Figure 4.13) The price level remains similar as the one observed in the Netherlands, within a small range of 2.7 and 2.8 €/kg across countries.

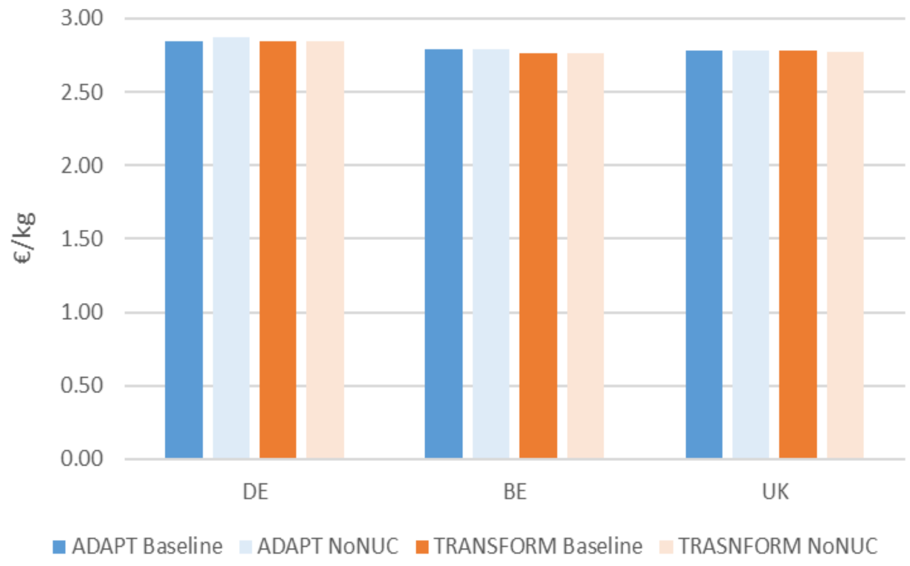



Figure 4.13: Hydrogen WAMP (in €$_{2015}$) for Germany, Belgium, and the UK in 2050.

### 4.2.5 Impact on deployment of flexibility

As energy systems introduce higher shares of variable sources such as wind and sun, system flexibility becomes paramount. The concept of flexibility in the present study comprises the capability of the system to adapt to variable power loads while respecting technical constraints. The sources for this flexibility can be multiple. From a supply side, flexibility can be provided through dispatchable generation (such as gas units) or through curtailment of VRE. From a demand side, demand response (DR) or demand curtailment can provide flexibility services, and other options, such as storage and trade can contribute flexibility from both sides of the balance.

The operation of NPPs in COMPETES-TNO shows the capacity to provide a certain level of flexibility from the supply side by behaving as a load-following technology. This can lead to competition against other flexible options in the system. In this section, we quantify this effect on storage and conversion technologies capacity, namely electrical storage and electrolysers. The effects on trade will be explored in more detail in the following section 4.2.6.

Figure 4.14 shows the installed capacities of storage and electrolysers in the Netherlands for the Baseline and the resulting changes under the NoNuclear cases for ADAPT and TRANSFORM. A noticeable difference between the scenarios is the difference in electrolyser capacity, especially in 2050. As seen previously in Figure 4.2, the difference in electrolysis due to the underlying different hydrogen demands, results under TRANSFORM with near 38 GW installed against the 12 GW in ADAPT in 2050. The differences between NoNuclear and Baseline is also derived from the divergences in the P2H2 demand, where lower electrolysis due to higher electricity prices result in TRANSFORM and ADAPT with around 4 GW less of electrolysers. Figure 4.15 displays the load duration curve of the electrolysers across the year in all cases and scenarios, showcasing the increase in FLHs of this technology from around 3700h to 3900h in TRANSFORM, and 4100h to 4400h in ADAPT.

Another difference between the scenarios is found on storage. Whereas ADAPT presents Compressed Air Energy Storage (CAES) and battery Li-ion, TRANSFORM only presents Li-Ion battery as the main electric storage technology. It is important to notice that the starter capacity of CAES and battery Li-ion in the scenarios is part of the existing vintage capacities from 2030 of OPERA. The optimization of COMPETES-TNO on 2040 shows that in the ADAPT and TRANSFORM Baseline, no storage capacities are further invested. Under the NoNuclear cases, differences are more noticeable in TRANSFORM, with a need of 1 GW (or 4 GWh) of storage. This trend of higher need of storage under the NoNuclear cases becomes fully apparent in 2050 for both scenarios, especially ADAPT with almost 5 GW of additional Li-ion batteries against the Baseline, and around 1 GW additional in TRANSFORM. This difference between scenarios is also related to the supply, as under ADAPT, solar PV constitutes a major share of the capacity mix. This results in higher demand for short-term flexibility, in this case provided by batteries.

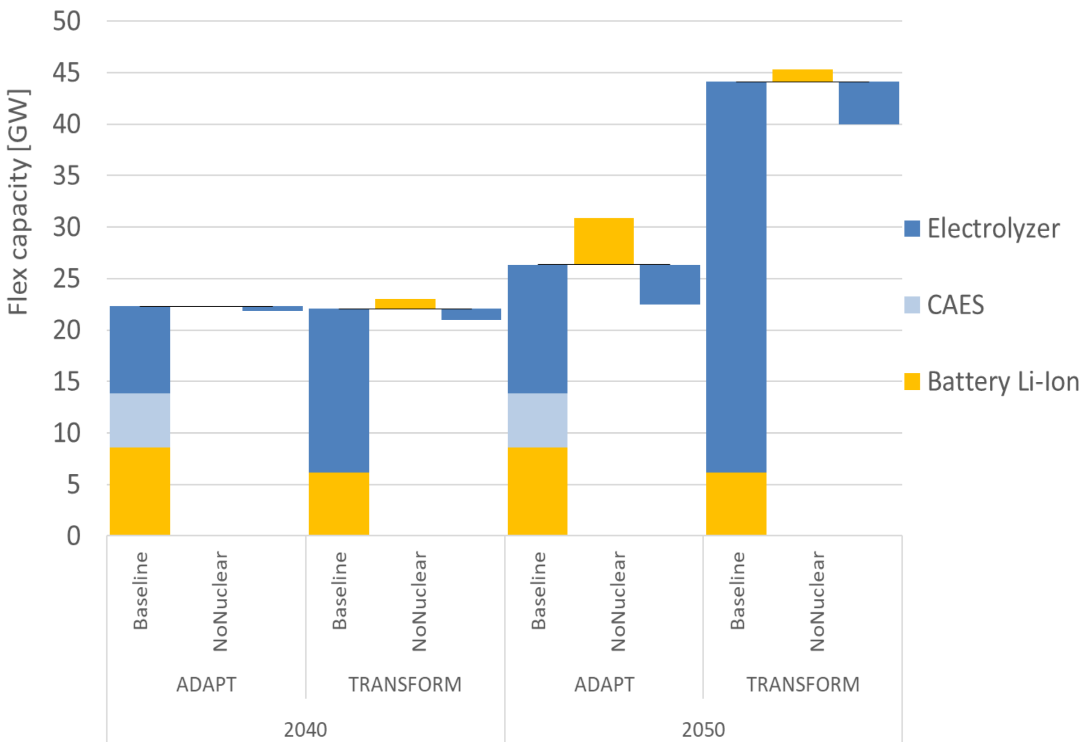



Figure 4.14: Installed capacity of electrical storage and electrolyser in the Netherlands for ADAPT and TRANSFORM for both cases in 2040 and 2050.

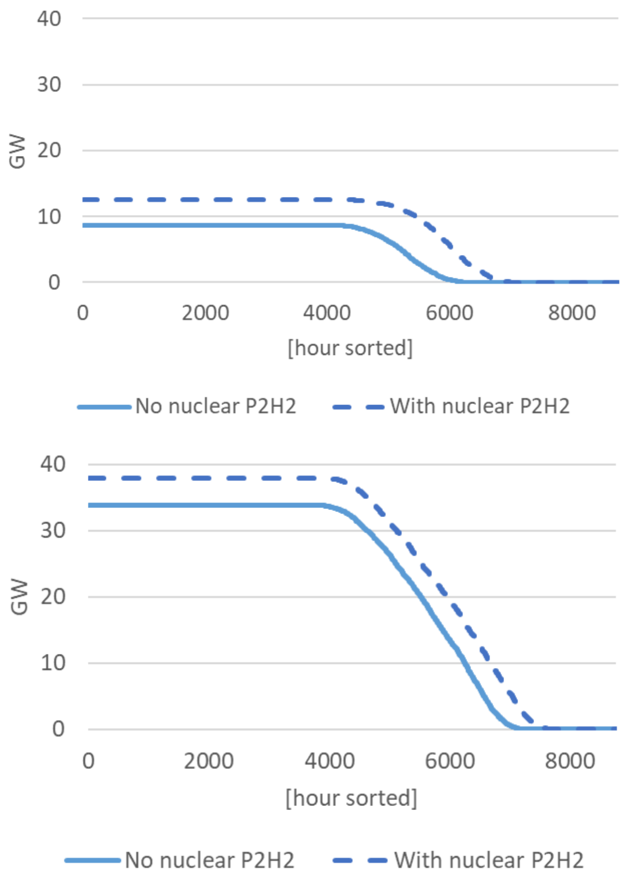



Figure 4.15: Duration curve of electrolyser operation for ADAPT (above) and TRANSFORM (below) in the Netherlands in 2050.

## 4.2.6 Impact on energy trade

Trade is a key flexibility option for the system, as it allows to export surpluses of energy, and to import to complement potential shortages of energy. In the case for electricity, the Netherlands is integrated in the European electricity network through interconnectors that allow the transmission of electricity between national systems and markets. This section explores the effect of nuclear on imports and exports dynamics for electricity in the Netherlands and selected surrounding countries, as well as the effect on trade for hydrogen. This trade dynamics are different from the ones observed in Chapter 3 by the OPERA model. As described in section 3.1.6, OPERA can diverge the imports and exports based on the abroad market price against the total costs of the commodity, whereas COMPETES-TNO is driven purely by market prices.

*Electricity*
Table 4.5 summarizes the imports and exports for the Netherlands in the different cases and scenarios, as well as the differences in net imports between the Baseline and NoNuclear cases. A negative value for net imports indicate that the Netherlands is importing more than exporting, whereas positive net imports values show that the Netherlands is a net exporter.

The overall trend, already observed in Table 4.5, is that under the NoNuclear cases the Dutch system relies more on imports from abroad. For the TRANSFORM Baseline, a surplus of electricity generation by nuclear generation allows for the Netherlands to become a net electricity exporter in 2050.

Table 4.5: Total electricity imports and exports in the Netherlands for the different cases and scenarios and resulting net imports (imports – exports)

| [TWh] | | ADAPT | | TRANSFORM | |
|---|---|---|---|---|---|
| | | 2040 | 2050 | 2040 | 2050 |
| Baseline | Imports | -49.3 | -53.8 | -48.0 | -53.3 |
| | Exports | 44.8 | 51.1 | 48.8 | 55.7 |
| | Net imports | -4.5 | -2.7 | 0.8 | 2.4 |
| NoNuclear | Imports | -49.8 | -58.8 | -49.6 | -56.4 |
| | Exports | 44.2 | 45.9 | 46.6 | 52.0 |
| | Net imports | -5.6 | -12.9 | -3.0 | -4.4 |

Other surrounding countries that are net importers, such as Germany, Belgium and the UK, experience a marginal decrease in their net imports in the NoNuclear case in both scenarios (in the order of 3-4 TWh less). This is a direct effect of the lower availability of surplus energy from the Netherlands, which needs to be compensated by higher domestic generation, as observed previously in Figure 4.7. Effects on net exporting countries, such as Denmark or France, are also negligible, with changes in their net imports under 1-2 TWh margin.

*Hydrogen*
Regarding hydrogen trade (see Table 4.6), the Netherlands perceives a significant increase in hydrogen import needs in the NoNuclear cases, with about 20 TWh extra in 2050 in both ADAPT and TRANSFORM. As seen previously, domestic production through electrolysers decreases in this case, leading to other sources (mainly through imports) to supply the domestic hydrogen demand.

Table 4.6: Total hydrogen imports and exports in the Netherlands for the different cases and scenarios and resulting net imports (imports – exports)

| [TWh] | | ADAPT | | TRANSFORM | |
|---|---|---|---|---|---|
| | | 2040 | 2050 | 2040 | 2050 |
| Baseline | Imports | -172.0 | -233.8 | -176.1 | -213.1 |
| | Exports | 168.8 | 185.4 | 145.8 | 167.9 |
| | Net imports | -3.2 | -48.4 | -30.3 | -45.2 |
| NoNuclear | Imports | -171.1 | -255.1 | -177.0 | -221.4 |
| | Exports | 165.4 | 185.5 | 141.3 | 153.7 |
| | Net imports | -5.7 | -69.6 | -35.7 | -67.7 |

Surrounding countries also experienced changes in their hydrogen trade between the Baseline and NoNuclear scenarios. However, consistent with previous findings, these variations are marginal and largely negligible

### 4.2.7 Impact on profitability of key technologies

This section analyses the impact of nuclear integration on the profitability of the major generation technologies of the Dutch power system in 2040 and 2050 by means of the following indicators:

- Average capture prices
- Levelized costs of energy (LCOE)
- Profits per MWh generated

Note that prices, levelized costs and profits are expressed in 2015 euros. In 2024 euros, costs and prices are approximately 30% higher.

*Average capture prices*

Average capture prices are the weighted average electricity prices that producers receive for their generation output over a certain period of time (usually one year).[23] Figure 4.16 presents the average capture prices for the major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and NoNuclear cases of the ADAPT and TRANSFORM scenarios. It shows that, in general, average capture prices are highest for peak production (gas CCGT), lowest for VRE generation (sun/wind) and in-between for mid- or baseload output (large nuclear).[24]

In addition, Figure 4.16 indicates that, in general, expanding nuclear generation leads to lower average capture prices for all major power production technologies in all cases considered (except for gas CCGT in TRANSFORM 2040). For instance, in the NoNuclear case of TRANSFORM 2050, the average capture price for offshore wind amounts to 38 €/MWh compared to 35 €/MWh in the Baseline case of TRANSFORM 2050 (which includes 8.1 $GW_e$ of nuclear capacity investments and 54 TWh of nuclear output generation).[25]

*Levelized costs of energy (LCOE)*

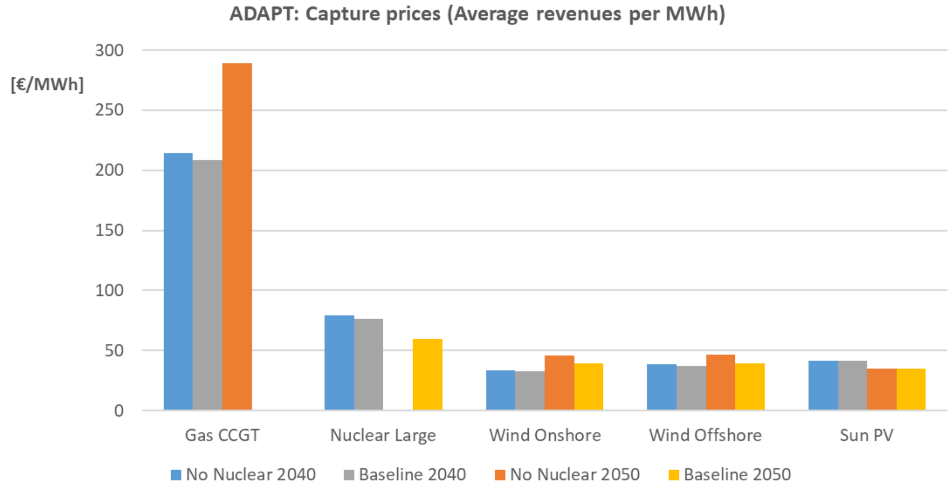
Levelized cost of energy (LCOE) are the average total costs of producing one unit of energy – e.g., 1 MWh of electricity – by a certain technology, levelized over the total output during its techno-economic lifetime. This indicator covers both (i) the average (levelized) capital investment costs of the technology (CAPEX), including a social/private discount rate (WACC), (ii) the average, fixed operational and maintenance costs of the technology (O&M), and (iii) the variable costs per unit produced, but it excludes wider system integration costs such as

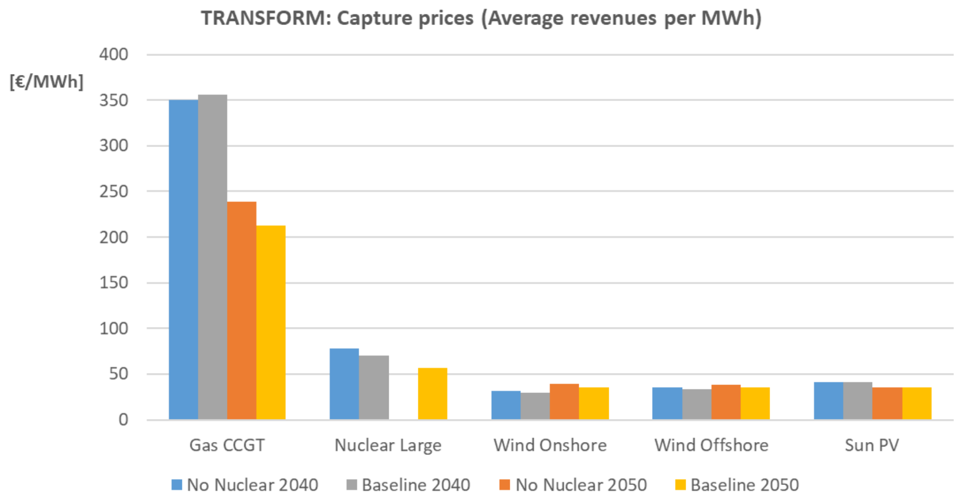
[23] Average capture prices have been calculated by (i) multiplying the hourly production per generation technology by the corresponding hourly electricity price, (ii) aggregating these hourly revenues over the year concerned, and (iii) dividing the total annual revenues by the total annual output production of the technology concerned.

[24] The underlying data of the graphs presented in the current section are recorded in Appendix I. Small Modular Reactors (SMRs) are not included in the profitability analysis of the major generation technologies in this section, mainly because COMPETES-TNO does not consider the heat revenues of SMRs. In this study, all costs and prices are expressed in fixed euros of 2015 (which implies that in euros of 2025 these costs and prices would be approximately 40% higher).

[25] Note that the (additional) nuclear output generation in the Baseline is partly compensated by less domestic production from other technologies and more domestic electricity demand, notably by electrolysers, as analysed in Sections 4.2.1 to 4.2.3 above. These compensation effects reduce the impact on the average capture prices of all generation technologies.

grid or system balancing costs. LCOE may decline over time due to technological learning, resulting notably in lower average CAPEX per unit produced.[26]



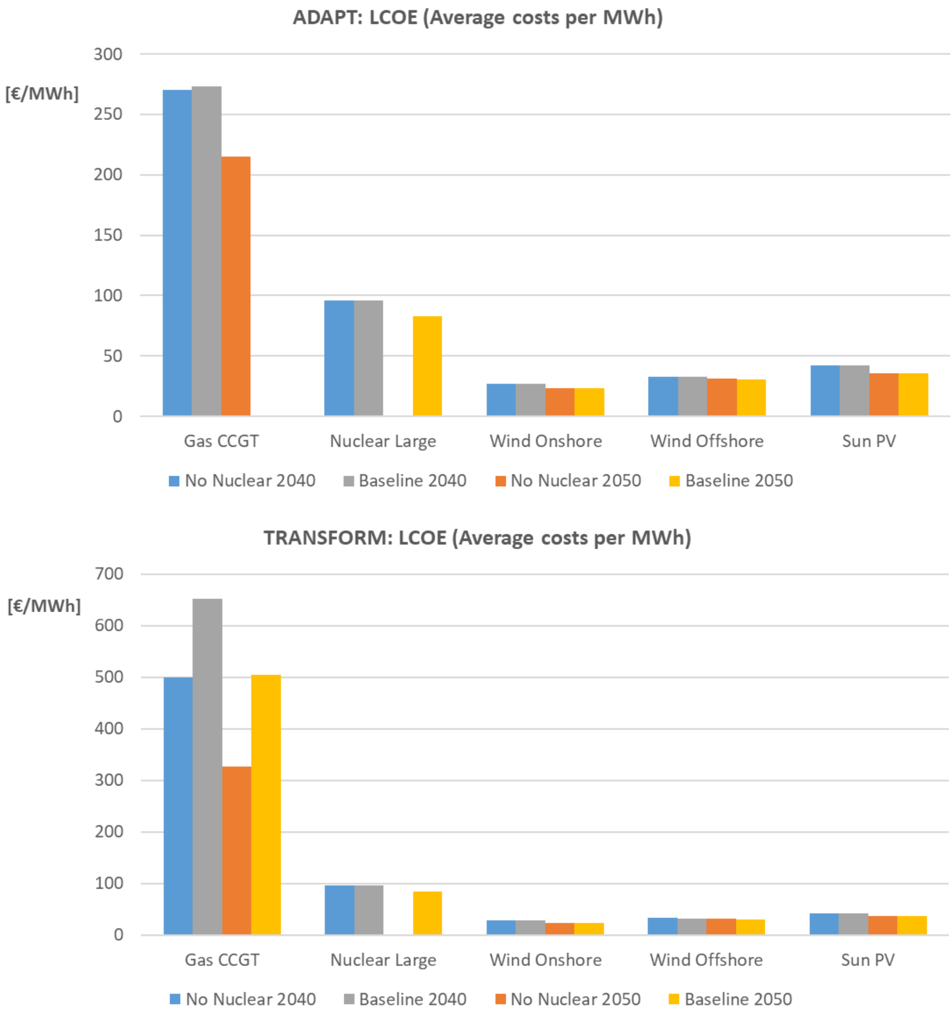

Notes: A missing bar – e.g., for 'Gas CCGT' in the Baseline case of ADAPT 2050 or for 'Nuclear Large' in the NoNuclear 2050 cases – indicates that the technology in question is not dispatched in the scenario concerned. The NoNuclear cases implies 'no new nuclear capacity investments'. So, any bar for 'Nuclear Large' in the NoNuclear 2040 case refers to the existing, installed nuclear plant in Borssele (which lifetime is assumed to be extended up to the early 2040s).

Figure 4.16: Average capture prices (in $€_{2015}$) of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and NoNuclear cases of the ADAPT and TRANSFORM scenarios

Figure 4.17 presents the LCOE of the major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and NoNuclear cases of the ADAPT and TRANSFORM scenarios. For instance, in the Baseline case of ADAPT 2050 the LCOE of large nuclear plants amounts to 83 €/MWh compared to 36 €/MWh for sun PV (see also Table I.1 in Appendix I, providing more detailed data).

[26] For this study, COMPETES-TNO has used a uniform discount rate of 6.5% for all technologies in all European countries/regions included in the model. In addition, for calculating the LCOE, it assumes that in each case – e.g., Baseline case of ADAPT 2040 – the annual output of a generation technology is representative for the (average) yearly production of that technology over its techno-economic lifetime.

Figure 4.17 indicates that, in general, the impact of nuclear expansion on the LCOE of other generation technologies is (nearly) absent, because it neither affects the costs of these technologies nor hardly their total (annual) output per unit capacity installed. The major exception is gas CCGT, where nuclear expansion results in substantially higher LCOEs for this gas-fired technology – notably in the TRANSFORM scenario – mainly due to less output/lower full load hours by gas CCGT (which raises the levelized fixed costs per MWh generated).




Notes: See Figure 4.16

Figure 4.17: Levelized costs of energy (LCOE) (in $€_{2015}$) of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the ADAPT and TRANSFORM scenarios

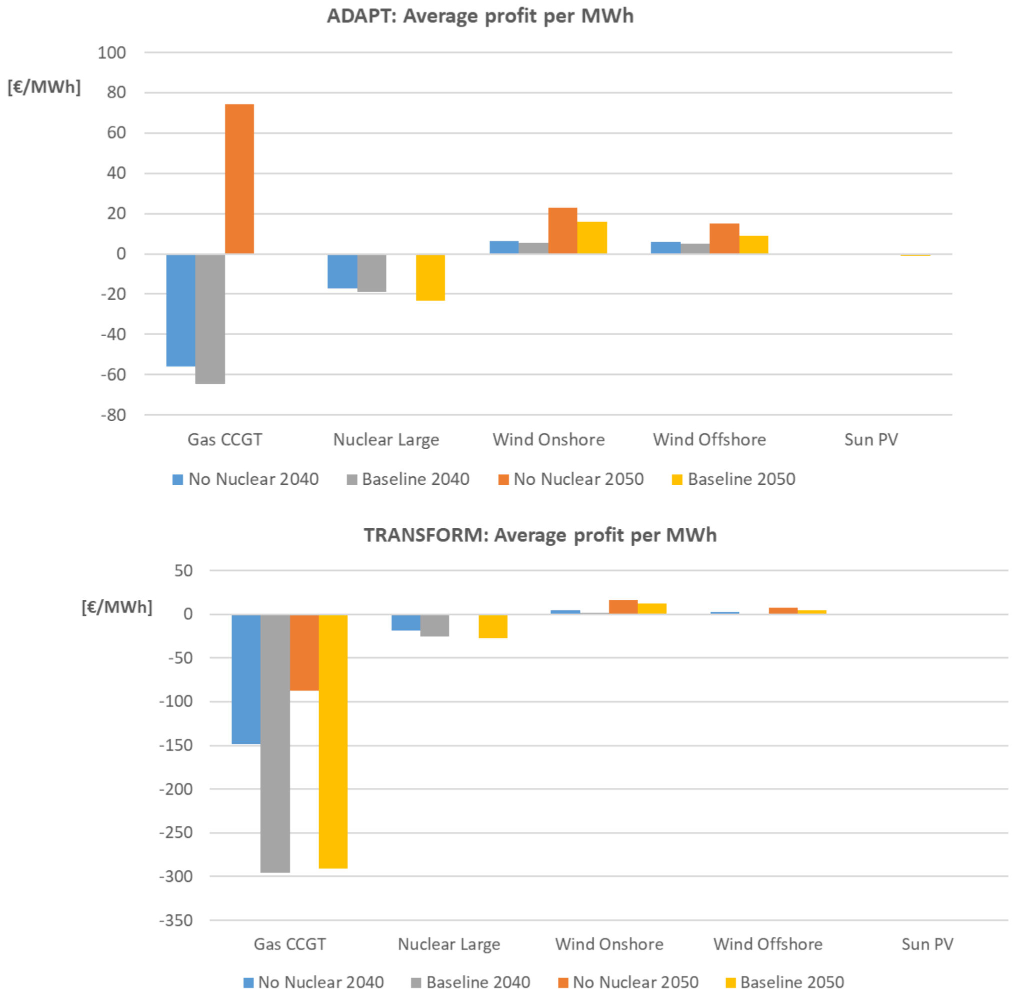
*Profits per MWh generated*

Profits per MWh generated are defined simply as the difference between the average capture price of a technology and its LCOE (as discussed in the sub-sections above).[27] Figure 4.18 presents the average profits per MWh of the major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the

[27] Alternatively, profits per MWh generated can be defined (and calculated) as the total annual revenues of a generation technology minus its total annual costs (including annualised CAPEX and fixed O&M costs), divided by its annual output production (in MWh).

ADAPT and TRANSFORM scenarios (see also in **Appendix I** for the underlying data of Figure 4.18).[28]

Figure 4.18 shows that, in general, the average profit per MWh generated is (i) highly negative ('major losses') for gas CCGT, except in the NoNuclear case of ADAPT 2050 where it is highly positive, (ii) slightly negative for large nuclear plants in all relevant cases, (iii) slightly positive for both wind onshore and offshore (partly because wind reaches its potential capacity caps), and (iv) close to zero for sun PV (for the exact numbers of the profits per technology, see Notes Table 1.2 in Appendix I).




Notes: See Figure 4.16

Figure 4.18: Profits per MWh (in $€_{2015}$) of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the ADAPT and TRANSFORM scenarios

The major reason why the losses per MWh produced by gas CCGT in 2040 and 2050 are relatively high (in most cases considered) is that the gas-fired plants concerned have been installed amply before 2030 (based on the price, cost and volume expectations by the time of the investment decision). Therefore, the investment costs (CAPEX) of these plants are considered as '*sunk costs*' (which have been either partly, largely or even – more than – fully

[28] Note that in COMPETES-TNO the levelized capital costs (CAPEX) are based on a uniform discount ('profit') rate of 6.5% for all technologies in all European countries/regions covered by the model. So, excluding or reducing this discount rate raises the average profits per MWh accordingly (whereas increasing this rate lowers these profits).

covered by the '*inframarginal rents*' of the output generated by these plants in the 2020s and 2030s).[29] Hence, in those hours in 2040-2050 in which the electricity price is higher than the variable costs of gas-CCGT-fired power production (i.e., generating a positive inframarginal rent), the plants concerned are still dispatched (rather than decommissioned), although usually in a limited – and even declining – number of hours. In these hours, however, the average capture price of gas CCGT does not cover its full LCOE (including fixed O&M and CAPEX per unit produced), resulting in a (significant) loss per MWh generated. A similar reasoning applies for the large nuclear plant in Borssele (as covered in the NoNuclear investment cases of both ADAPT and TRANSFORM 2040). This plant was already installed in the 1970s while its lifetime is assumed (exogenously in COMPETES-TNO) to be extended up to the early 2040s. Whereas in most hours of 2040 the variable, operational costs of the Borssele plant are covered by the electricity price, its full LCOE is significantly higher than its average capture price, resulting in significant losses, i.e. about 17-19 €/MWh, in the NoNuclear investment cases of both ADAPT and TRANSFORM 2040.

New investments in nuclear capacity, however, also show 'negative profits' per MWh produced in all relevant cases considered (see Figure 4.18). For instance, in the Baseline cases for 2050 the losses for large nuclear plants amount to 23 €/MWh in ADAPT and 28 €/MWh in TRANSFORM. The major reason for this performance is that, at least according to the COMPETES-TNO model for these scenario cases, new nuclear investments are not 'cost-optimal' from a European power system perspective. Therefore, the installed nuclear capacities have been assumed exogenously by COMPETES-TNO (based on baseline, cost-optimal results from the NL integrated energy system model OPERA), resulting in losses for nuclear investments in the COMPETES-TNO model runs.[30]

The losses per MWh provide a first, rough indication of the support or subsidy per MWh required to induce the capacity investments of the technologies concerned. Multiplying these losses by the total annual output per technology gives a rough estimate of the total support ('subsidy') needed. For instance, in the Baseline case of TRANSFORM 2050 the loss by large nuclear plants amounts to 28 €/MWh whereas the output of these plants amounts to 41 TWh, resulting in a total loss ('subsidy required') of approximately 1.1 billion € (see also the considerations and qualifications in the Section 4.3).

Finally, Figure 4.18 indicates that the *impact* of nuclear expansion on the profitability of the *other* technologies is, on balance, generally small for sun and wind but quite substantial for gas CCGT (notably in the TRANSFORM scenario cases). For instance, in TRANSFORM 2050 the profitability of offshore wind amounts to 16 €/MWh in the NoNuclear case compared to 12 €/MWh in the Baseline case, whereas for gas CCGT these figures amount to -88 €/MWh and -291 €/MWh, respectively (see also Notes Table I.3 in Appendix I). As analysed in the sub-sections above, the relatively small impact of nuclear expansion on the profitability of offshore wind (-4 €/MWh) is primarily due to the small negative effect of more nuclear output on the average capture price of offshore wind (and hardly or not on its LCOE). On the other hand, the relatively large impact of nuclear integration on the profitability of gas CCGT

[29] Inframarginal rents are the difference between the (hourly) electricity prices ('marginal revenues') and the variable costs per unit produced ('marginal costs'). These rents are primarily meant to cover the CAPEX and fixed O&M costs and, subsequently, generate extra profits.

[30] Once again, it should be noted that the LCOE of large nuclear plants include a discount ('profit') rate for capital investment costs (CAPEX) of 6.5% per annum. Excluding or reducing this rate decreases the average losses per MWh accordingly or may even turn it into average profits per unit generated. On the other hand, assuming a higher ('private') discount rate for nuclear investments implies that the losses of these investments will be even higher than recorded in **Figure 4.18** (see also the considerations in Section 4.3). Additionally, the technical minimum load constraint of nuclear can incur losses by forcing operation when it is not profitable (i.e. electricity prices are lower than the assumed nuclear marginal costs).

(-204 €/MWh) is only partly due to the negative effect on the average capture price of gas CCGT (-26 €/MWh) but mainly because of the large negative impact of its LCOE (i.e., 178 €/MWh higher due to the induced lower output/full load hours of gas CCGT).

## 4.3 Discussion

Some qualifications have to be added to the model scenario analyses in Chapters 3 and 4 in general and with regard to the profitability of nuclear power investments in Section 4.2.7 above in particular.

*Perfect foresight versus risks and uncertainties*
Both OPERA and COMPETES-TNO are so-called ‘cost-optimization’ models, i.e. they analyse how a certain energy demand over a certain period – usually a full year – can be met within a set of techno-economic and policy constraints at the lowest (social) cost. A major characteristic of these models is that they are based on ‘perfect foresight’, i.e. they assume the availability of full, free knowledge for investment decisions – notably concerning future costs, prices and market transaction volumes – and, therefore, these models hardly or not consider any uncertainties or risks regarding these investment decisions.

In practice, however, energy investments – notably in, e.g., power generation or infrastructure – are characterized by high risks and uncertainties. This applies in particular to investments in nuclear power generation, given the relatively long preparation and building phase of NPPs (10-15 years), the long operational phase of these plants (10-15 years) and, finally, the dismantling phase (>10 years).[31]

Due to these high, long-term risks and uncertainties, private parties are generally quite hesitant to invest in nuclear power generation and, therefore, they usually require a high profit (‘discount’) rate – including a high risk premium – on their investments and/or an extensive package of public (government) support mechanisms before they decide to invest. Such a package may include all kinds of public guarantees, public-private risk allocation and finance schemes, as well as various operational support mechanisms.[32]

The required profit rate on private capital investments in NPPs varies usually between 7-15% (KPMG, 2021), depending on the risk type of these plants (i.e., notably first-of-a-kind versus next/Nth-of-a-kind projects).[33] A higher profit (discount) rate results in a higher average cost level of a technology. For instance, assuming investment costs (CAPEX) of 6 m€/MW nuclear capacity and, on average, 6000 full load hours per annum for nuclear operation, a 1% higher profit rate raises the LCOE of nuclear energy by 10 €/MWh. More specifically, (EY, 2024) showed recently that by increasing the discount rate from 7% to 15% raises the LCOE of a new NPP from about 60 €/MWh to approximately 140 €/MWh. This indicates that in particular the higher profit rates – and resulting costs levels – are most likely not feasible (i.e., economically not viable) from a pure market perspective. Therefore, a wide package of government support measures is required to reduce the risks of nuclear investments and make them attractive from a private party point of view.

[31] For a schematic overview and brief discussion of the major risks of investments in a nuclear power plant during its different lifetime phases, see – among others – (KPMG, 2021). See also (Weibezahn & Steigerwald, 2024).
[32] For a recent discussion, analysis and advice regarding a ‘Government Support Package’ (GSP) for the ‘Dutch Nuclear New Built Program’, see (EY, 2024). See also (Parisbas, 2024) and (Ministry of Climate Policy and Green Growth, 2024) (Ministry of Climate Policy and Green Growth, 2025) as well as the discussion in the present section below.
[33] Note that these private profit rates are generally significantly higher than the discount rates applied by the (social) cost-optimization models in the present study, i.e. OPERA (2.5%) and COMPETES-TNO (6.5%).

Regarding the preparation and building phase of a NPP – but also during its dismantling phase – the risks and uncertainties refer notably to the *cost* side of the investment decision. In particular these risks and uncertainties concern higher investment costs (CAPEX) due to higher material/personnel costs, extra (safety) demands during the construction phase and/or all kinds of preparation and building delays, resulting in higher financing costs. This includes notably higher interest costs, depending on the public-private risk allocation and financing model selected and the resulting required public-private discount rates involved. More specifically, in order to address (reduce) the private cost risks and uncertainties of nuclear investments, a variety of private-public risk allocation schemes and financing models have been proposed and further developed, such as the Mankala model, the Regulated Asset Base (RAB) model or even full publicly financed investment schemes.[34]
On the other hand, regarding the operational phase of an NPP, the risks and uncertainties refer primarily to the *revenue* side of the investment decision, and (far) less to the operation and maintenance cost of running and dispatching the nuclear plant. These revenue risks and uncertainties refer in particular to the average capture price for a nuclear power producer but also to the full load hours – or total annual output – of a nuclear plant, notably in an electricity system with a high share of variable, low-cost renewables (sun/wind).
In order to address (reduce) private revenue risks and uncertainties, there are basically two options:

- *A long-term power purchase agreement (PPA).* A PPA is a commercial, long-term contract – usually for 5 to 20 years – between a (private) producer and consumer of electricity, whereby the consumer – e.g., a power-intensive industry or an electrolyser – agrees to buy a specified amount of electricity at a beforehand determined price (formula) over the contract period as a whole. Therefore, a PPA provides volume and price certainty to both the producer and consumer involved. PPAs, however, still suffer from a variety of shortcomings and other disadvantages – which limit their scope and impact – such as underdeveloped, low-liquid PPA markets, in particular lack of credible, both large- and small-scale power consumers over the long run, or problems with determining fixed, long-term contract prices that are acceptable to both parties (European Commission, 2023) (Sijm, 2024).
- *A price support ('subsidy') mechanism*, such as the Dutch SDE++ scheme or a so-called 'Contract-for-Differences (CfD)[35]. For the European Commission, the (two-way) CfD is the preferred support mechanism, notably for nuclear power generators (European Commission, 2023) (European Commission, 2024). In the energy domain, a CfD is an agreement between a public agency and a producer of (carbon-free) energy to offset the difference between the actual (market revenue) price and a so-called 'reference (target) price' of a unit energy produced.[36] The major advantage of CfDs is that they stimulate energy investments by reducing the price risks of these investments. On the other hand, the major disadvantage or risk of CfDs is that they may lead to distinct

[34] For recent analyses and discussions of these risks allocation schemes and finance models – notably in the context of the 'Dutch Nuclear New Build Program'- see, among others, (KPMG, 2021) and (KPMG, 2023), (Barringa, 2022), EY (2024), (Profundo, 2024), (Weibezahn & Steigerwald, 2024), as well as (Ministry of Climate Policy and Green Growth, 2024) and (Ministry of Climate Policy and Green Growth, 2025). Note (i) that with regard to the risks and uncertainties of nuclear capital investments the key challenge is getting agreement on an adequate risk allocation scheme between private and public parties involved (rather than reducing private risks per sé), (ii) that some risks – and the costs concerned – apply more or less equally to both private and public parties (although public parties may be better able or more willing to bear these costs), and (iii) that some risks – e.g., related to the agreed, direct building of the nuclear power plant – can be better born, controlled or mitigated by the private party concerned, i.e. the private constructor of the plant.

[35] SDE scheme is an example of a one-sided CfD.

[36] Usually, a distinction is made between 'One-Way CfDs' and 'Two-Way CfDs (for further details see, among others, (European Commission, 2023) and (Sijm, 2024)).

disruptions of short-term energy markets, such as reducing the incentives for providing flexibility to the power system or lowering allocative efficiency of the electricity market, depending on the specific design elements of a CfD. In general, however, there seems to be a certain trade-off between the specific design elements of a CfD ('complexity'), its practical feasibility ('implementation') and its short-term energy market effects ('efficiency').[37]

*Energy-only-markets versus capacity mechanisms*
In addition, it should be noted that the analyses in Chapter 4 in general and with regard to the profitability of nuclear power investments in Section 4.2.7 in particular are based on a so-called 'Energy-only-market' (EOM) approach, notably on a model scenario approach of the hourly electricity spot market only.[38] The core of such an EOM approach is that (private) investors in power generation capacity should cover the costs of their investments solely from market revenues of their electricity output (and not from additional subsidies or any other compensations, e.g. for safeguarding the availability of a certain back-up capacity). Over the past decades, there has been an extensive, ongoing discussion whether energy-only-markets can guarantee adequate investments in power generation capacity and, therefore, safeguard the reliability and adequacy of the power system in both the short, medium and long term (notably in a system characterised by a high share of variable, low-cost renewables).[39] In theory, they could – if certain conditions are met – but, in practice, there are often all kinds of constraints and other barriers such as (scarcity) price caps or high future market risks and uncertainties.

As discussed above, these market risks and uncertainties apply in particular to (private) investments in nuclear power capacity, given the very long-term, high capital-intensive characteristics of these investments. Besides the options already mentioned above (i.e., PPAs and CfDs), there is a third, alternative option to deal with this issue, i.e. the introduction of a '*capacity mechanism*' (not only for investments in nuclear power generation but, from an equal playing field perspective, also for other – carbon-free – electricity production technologies).[40]

There are several types of capacity mechanisms but, in general, they stimulate investing in new generation capacity and/or maintaining existing capacity. The major types of these mechanisms include (i) strategic reserves, (ii) capacity markets (either central or decentral), (iii) capacity tenders, and (iv) capacity subscriptions.[41] Each of these mechanisms knows several variants and sub-variants, each with their pros and cons, depending on the specific design elements of the variants and sub-variants. It is beyond the scope of the present study to further explore this wide variety of capacity mechanisms but, for now, the key

[37] For a discussion of the pros and cons of different options for various CfD design elements, see – among others – (Fabra, 2022), (Schlecht & Hirth, 2024), (Trinomics, 2024), (Kitzing, et al., 2024) and (Johanndeiter, Helistö, & Bertsch, 2025).
[38] Besides the hourly spot market, there are some other electricity markets such as the balancing (reserve) markets or the ancillary services markets. In general, compared to the hourly spot market, the (future) impact of nuclear power generation in the Netherlands on these other markets is expected to be relatively small while, on the other hand, the impact – e.g., potential revenues – of these markets on the performance of nuclear power generation (installed capacity, output, profitability, etc.) is also expected to be relatively small. Therefore, these other electricity markets have not been included or considered in the present study.
[39] For a recent contribution and literature review of this EOM discussion, see – among other – (Sanchez Jimenez, et al., 2024)Sanchez Jimenez et al. (2024), and references cited there.
[40] As noted, however, for the European Commission (two-way) CfDs are the preferred option to support investments in (carbon-free) generation technologies – besides PPAs – but, under certain conditions, the Commission allows also certain capacity mechanisms (EC, 2023 and 2024).
[41] Note that although the EC considers strategic reserves as part of capacity mechanisms, these reserves do not necessitate a change of the EOM approach and can be considered as a way in between the EOM approach and more far-reaching capacity mechanisms such as capacity markets, tenders, and subscriptions.

message is that – besides PPAs and CfDs – capacity mechanisms are an option to stimulate or maintain (private) investments in nuclear power capacity, notably if policy or society opts for supporting this technology from a social-optimal system point of view.[42]

*Conclusion*

The analyses in the present study – in particular in Chapter 4 – are largely based on scenarios runs by means of system optimisation modelling, including assumptions such as 'perfect foresight' and 'energy-only-markets'. In practice, however, (private) long-term, capital-intensive investments in nuclear power generation are characterized by high risks and uncertainties on both the cost and revenue side of these investments, notably in future – carbon-free – power system with a high share of variable, low-cost renewables (sun/wind). Therefore, private parties will only invest in nuclear energy up to the policy or socially desired optimum if they expect (unfeasible) high profit rates – including a high risk premium – and/or have access to a wide 'government support package' (GSP), including public-private risk allocation and finance schemes, as well as additional market support mechanisms such as long-term power purchase agreements (PPAs), contracts-for-differences (CfDs) or certain types of capacity mechanisms (CMs).

[42] For the large literature on the wide variety of capacity mechanisms, see – among others – (Sijm, 2024) and references cited there.

# 5 Nuclear fuel cycle

In this Chapter, the results related to the nuclear fuel cycle are presented. The analysis is performed using the methodology described in Section 2.1.4, using the parameters provided in Section 2.4. The results from scenario analysis, namely the installed capacity in the two base cases ADAPT and TRANSFORM (see Chapter 3, Table 3.1), serve as input for the scenario analysis. Both of these scenarios are analysed in two variants (a fuel cycle using only enriched uranium (UOX), and a fuel cycle with partial usage of reprocessed plutonium (MOX)), as discussed in Section 2.2.3. In addition, the existing Borssele reactor operating regime is extrapolated towards the projected end-of-life (BORSSELE scenario).

Section 5.1 and Section 5.2 presents and analyses results for the BORSSELE and ADAPT and TRANSFORM scenarios, respectively. In Section 5.3 a comparison is made between the different results of scenarios and variants. Finally, in Section 5.4 the feasibility of the scenarios is discussed.

## 5.1 BORSSELE scenario (BAU)

### 5.1.1 Front-end

EPZ, the Borssele reactor operator, has reported using UOX based fuels with the fissile material coming from various sources, such as enriched natural uranium, re-enriched depleted uranium, (compensated) enriched reprocessed uranium or downblended military grade uranium. Which source is used varies from year to year (EPZ, sd), and how this distribution will look in the future is not (publicly) known. Therefore, the assumption is made that in the future 50% of the uranium will be sourced from primary sources (natural uranium), and 50% from secondary sources (such as reprocessed uranium).

The Borssele reactor uses a core composed of 40% MOX and 60% UOX. The plutonium used for the MOX is sourced from  reprocessed UOX fuel from Borssele's spent fuel or can be acquired from other sources. Both of the ingredients of MOX, depleted uranium and reprocessed plutonium, are byproducts from other activities in the (global) nuclear fuel cycle. They do not contribute to the usage of new primary sources, unlike natural uranium based fuels.

The Borssele reactor fuel has a burn-up of 53 MWd/kgHM, and a thermal power of around 1365 MW. Therefore, the largest fuel consumption rate (assuming a capacity factor of 90%), is 8.5 tHM/year (tHM: tonne of heavy metal). This is then also the amount of fuel that needs to be reprocessed each year. Of this fuel, 60% is assumed to be UOX, of which 50% is considered to be natural uranium based. Therefore, the enriched natural uranium demand is 2.5 tHM/year. The other 50% is considered reprocessed uranium. The enriched reprocessed uranium demand is also 2.5 tHM/year. The reprocessed uranium must be enriched to 4.6% (EPZ, 2010) from spent uranium, which has a U-235 content of around 0.7% (EPZ, 2010).

With an enrichment of 4.4% for the enriched natural uranium, and 4.6% for the re-enriched reprocessed uranium, the following metrics can be derived:

- Natural uranium
  - Demand for natural uranium of 22.4 tHM/year.
  - Production of depleted uranium due to enrichment of 19.9 tHM/year, which when adjusted for the consumption rate of MOX (92% depleted uranium) reduces to a net value of 16.7 tHM/year.
  - Demand for enrichment of 16.7 tHM-SWU/year.
- Reprocessed uranium
  - Demand for reprocessed uranium of 24.5 tHM/year.
  - Production of depleted uranium due to enrichment of 22.0 tHM/year.
  - Demand for enrichment of 18.2 tHM-SWU/year.
- MOX
  - Demand for MOX fuel of 3.4 tHM/year.
  - Consumption of depleted uranium of 3.1 tHM/year.

These metrics are integrated the period 2025 – 2043 (i.e. from the current point in time till end-of-life), which are given in Table 5.1.

Table 5.1: Total amount (tHM) of natural (Unat), enriched (ENU) uranium and SWU (Separative Work Unit) required, the amount of depleted uranium (DU) produced in the BORSSELE scenario.

| Scenario | Total SWU | Total Unat | Total ENU | Total DU |
|---|---|---|---|---|
| BORSSELE | 629 | 403 | 46 | 751 |

## 5.1.2 Back-end

The spent fuel of the Borssele reactor is reprocessed, and the HLW is stored in CSD containers. COVRA reports on the yearly amount of HLW delivered due to this process, which is 5.6 $m^3$ (Burggraaff, Welbergen, & Verhoef, 2022). This amount includes both the CSD-Vs with vitrified waste and CSD-Cs with compacted waste. The distribution between these two types is not congruent with the expected distribution as described in Section **2.4.2**, since a trade deal is in place with the reprocessing supplier in which the different types of containers can be exchanged for an equivalent radiotoxic value (Hart & Jansma, 2022). Conservatively, it is assumed that all HLW containers COVRA receives are CSD-Vs, since they are more difficult to store (i.e. they need to be stored on the 'hot' side, requiring cooling).

The amount of containers received per year is taken as the volume received by COVRA, divided by the container volume (190 L), which is around 30. This rate, and the yearly SNF production, are integrated over the period 2025 – 2043 (i.e. from the current point in time till end-of-life), which is given in Table 5.2.

Table 5.2: The total expected amount of spent fuel to be stored, or the amount of reprocessing waste to be temporarily stored pending final disposal (depending on spent fuel management strategy).

| Scenario | SNF [tHM] | Number of packages (reprocessed waste) | Volume of packages [$m^3$] |
|---|---|---|---|
| BORSSELE | 152 | 531 | 101 |

## 5.2 ADAPT and TRANSFORM

### 5.2.1 Front-end

Table 5.3 and Figure 5.1 show the amount of natural (Unat) and enriched (ENU) uranium required, the amount of depleted uranium (DU) produced and the amount of separative work units (SWU) required for the ADAPT and TRANSFORM scenario for fuel cycle variants A and B. Within the graph, a number of peaks can be identified. These peaks correspond to the years that new reactors come online. In those years, the demand for fuel is multiple times larger because an entirely new core needs to be supplied, instead of only a fourth per reloading cycle. Because part of the reactors in variant B run on MOX fuel, the required amount of natural uranium, enrichment, and the production of depleted uranium is lower than in variant A. Additionally, DU is also consumed by the use of MOX in variant B, as a result of which the net amount of DU is slightly lower than indicated.

Table 5.3: Total amount (tHM) of SWU, Unat, ENU required per scenario, and the amount of DU produced.

| Scenario | SWU | Unat | ENU | DU |
|---|---|---|---|---|
| ADAPT A (UOX) | 70,300 | 91,100 | 9,200 | 81,900 |
| ADAPT B (UOX/MOX) | 59,300 | 76,900 | 7,800 | 69,100 |
| TRANSFORM A (UOX) | 69,200 | 89,600 | 9,100 | 80,600 |
| TRANSFORM B (UOX/MOX) | 58,400 | 75,600 | 7,600 | 68,000 |

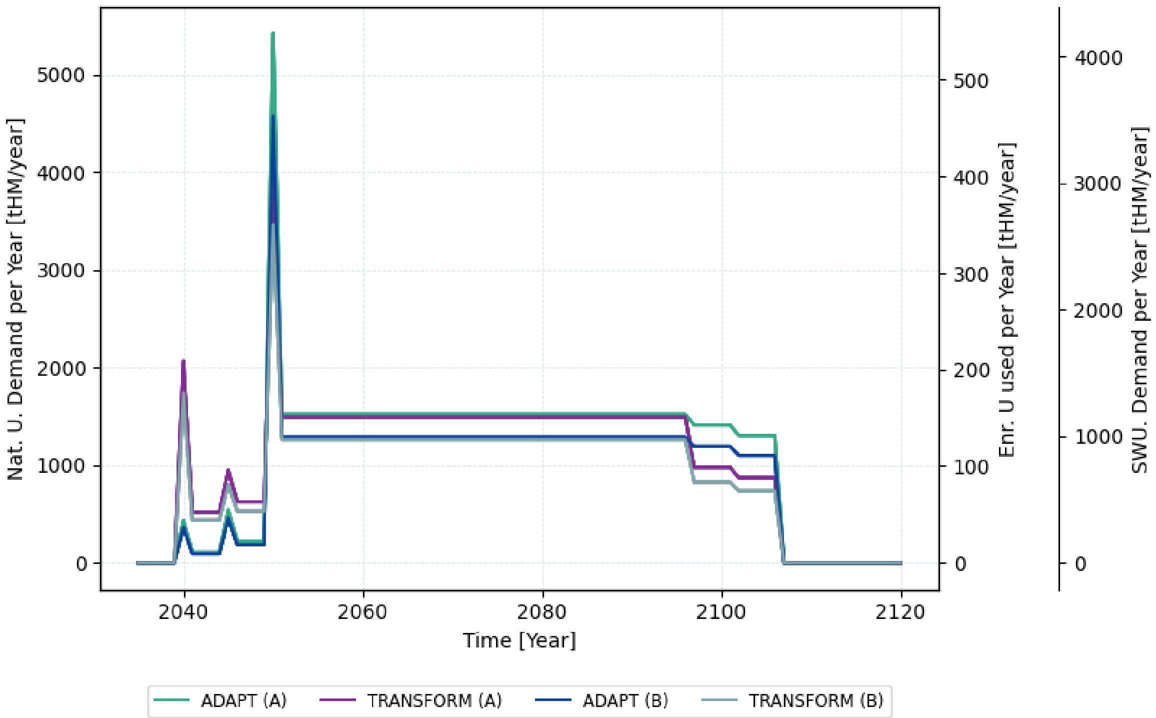



Figure 5.1: The amount of natural uranium, enriched uranium and SWU required over time for the different scenarios ADAPT and TRANSFORM in combination with fuel-cycle variants A and B.

### 5.2.2 Back-end

Based on the calculated amount of SNF per scenario, the amount of container volume in case of dry storage of spent fuel (CASTOR containers) was determined. After the initial cooling period (5 years), the decision whether or not to reprocess the spent fuel is made. After reprocessing, the materials classified as waste are placed in an interim storage facility for an extended period of time until they can be transferred to a final disposal. Table 5.4 shows the total amount of waste to be stored in this way, if there is no final disposal facility to transport the waste before the closure of the last reactor (meaning the stored waste keeps accumulating). The values for variant A and B are the same, except for the amount of volume of the CSD-Vs, because all other parameters are identical.

Table 5.4: The total expected volume of SNF/reprocessing waste to be temporarily stored pending final disposal, depending on the method of storage. The number of containers is calculated using the assumed 5 year cooling period.

| Scenario | SNF [tHM] | Without reprocessing | | With reprocessing | |
|---|---|---|---|---|---|
| | | Volume fuel assemblies [$m^3$] | Volume CASTORs [$m^3$] | Amount of CSD-Vs | Volume CSD-Vs [$m^3$] |
| ADAPT A (UOX) | 9209 | 3411 | 27086 | 16804 | 3193 |
| ADAPT B (UOX/MOX) | 9209 | 3411 | 27086 | 19753 | 3753 |
| TRANSFORM A (UOX) | 9060 | 3355 | 26646 | 16564 | 3147 |
| TRANSFORM B (UOX/MOX) | 9060 | 3355 | 26646 | 19466 | 3698 |

The total quantity of vitrified waste containing CSD-Vs over time in both scenarios is shown in Figure 5.2. This graph can be used to determine the required storage capacity in a given year. Due to the increased actinide concentration of the MOX fuel, the required amount of waste containers is slightly larger in the B variant scenarios.

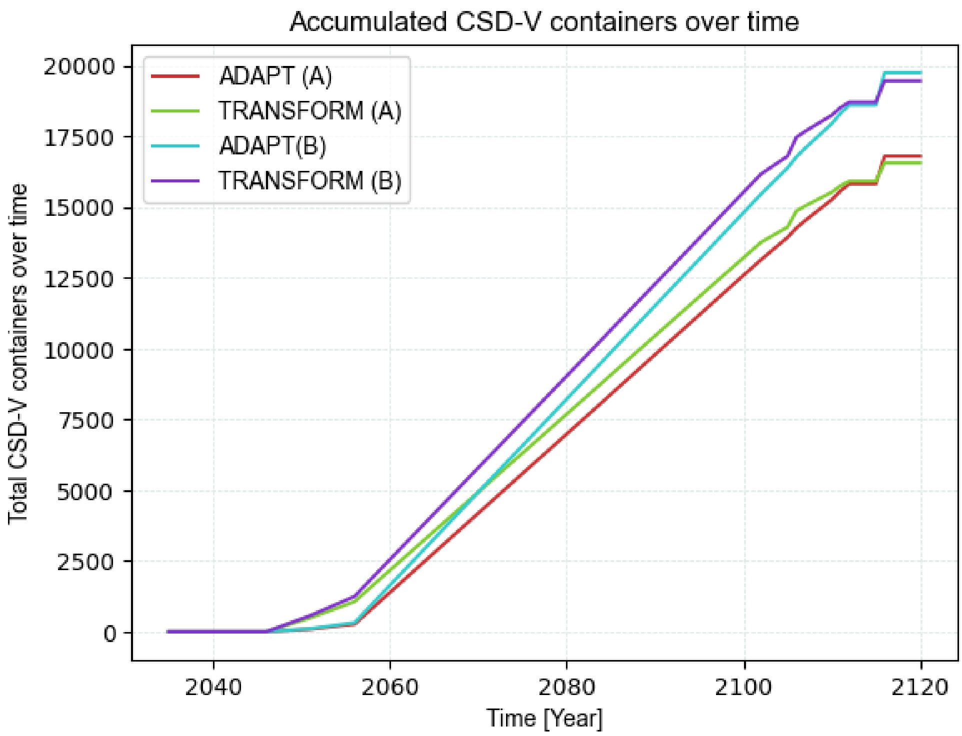



Figure 5.2: The total quantity of accumulated CSD-V containers per scenario and fuel cycle variant.

Figure 5.3 shows in two scenarios and two variants the amount of depleted uranium (DU) to be expected over time, being the by-product uranium enrichment for fuel. This is not necessarily equal to the actual amount of DU that needs to be stored over time at COVRA, because COVRA receives the DU from Dutch uranium enrichment facility Urenco related to their production for clients in various countries. The amount of DU to be stored presented in the analysis refers only to what is produced for Dutch nuclear reactors. The results show that the production of DU is lower in the variant B scenarios, since less uranium needs to be enriched.

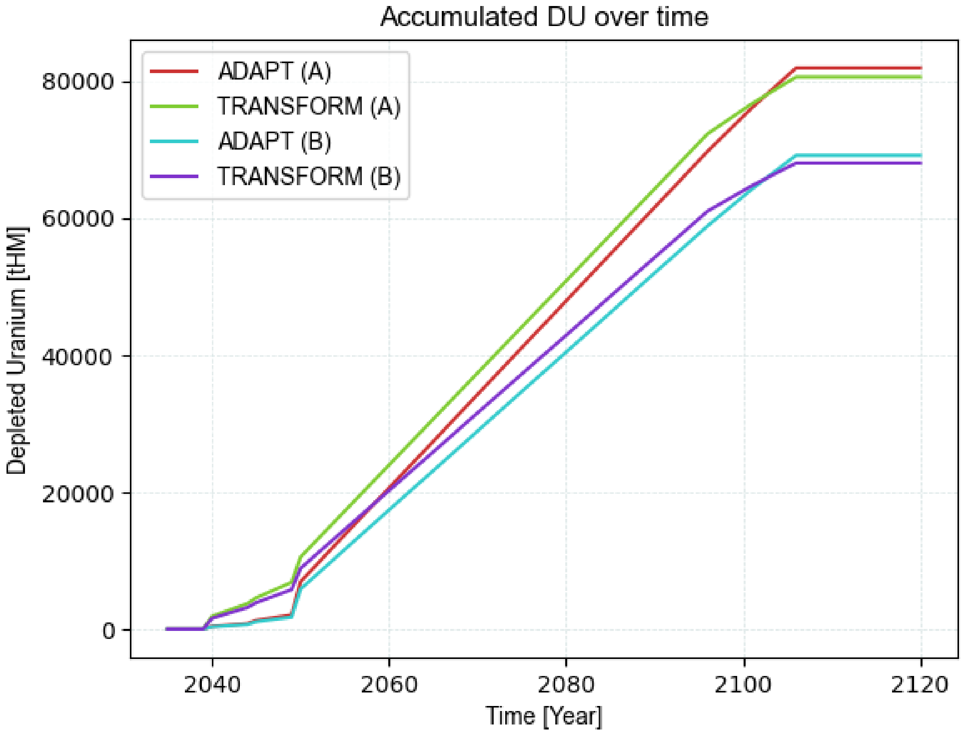



Figure 5.3: Amount of depleted uranium produced from the tails of the uranium enriched for the Dutch reactor fuel in each scenario.

In variant B, Pu is separated from the spent UOX (around 84% of the fuel) and added to the MOX (around 16% of the fuel). The total mass fraction of Pu in the MOX is 8.4%, of which 5.4% is fissile. The spent MOX waste results in 6.3 wt% (LR-MOX) to 6.8 wt% (SMR-MOX). This effectively means that the amount of plutonium has decreased by about a quarter at the end of a fuel cycle (8.4% to 6.3 – 6.8%). This is reflected in the results for the final amount of separated Pu for the different scenarios, which can be seen in Table 5.5, the amount of Pu in variant B is indeed about three-quarters of variant A.

Table 5.5: Total amount of reprocessed plutonium and uranium [tHM] at the end of the calculation from the different scenarios and variants.

| Scenario | Separated plutonium | | Separated uranium | |
|---|---|---|---|---|
| | Variant A | Variant B | Variant A | Variant B |
| ADAPT | 130.0 | 89.6 | 8550.6 | 8473.4 |
| TRANSFORM | 128.0 | 88.1 | 8410.3 | 8334.4 |

## 5.3 Comparison of the scenarios and variants

The collection of results of all scenarios are presented in this section. In order to properly interpret the results of the ADAPT or TRANSFORM scenarios, a comparison is made with the results of the BORSSELE scenario.

### 5.3.1 Front-end

Table 5.6 shows the total demand of different fuel products/facilities for the different scenarios and variants. To compare these values with the nuclear industry capacities, it is also useful to know what the maximum annual demand is over the time frame of the scenario, which is shown in Table 5.7. The amount of natural uranium and enrichment required is in proportion to the amount of UOX used. This means that variant B requires 84.4% of the natural uranium and SWU requirement of variant A.

Table 5.6: Comparison of the total net amount of DU produced, SWU required and net amount of plutonium produced. All values in tHM.

| Scenario | Unat demand | ENU production | Net DU production | SWU | Net Pu production |
|---|---|---|---|---|---|
| BORSSELE | 403 | 46 | 751 | 629 | 8 |
| ADAPT A (UOX) | 91114 | 9209 | 81905 | 70302 | 130 |
| ADAPT B (UOX/MOX) | 76900 | 7773 | 67811 | 59335 | 199 |
| TRANSFORM A (UOX) | 89632 | 9060 | 80572 | 69158 | 128 |
| TRANSFORM B (UOX/MOX) | 75649 | 7646 | 66708 | 58370 | 196 |

Table 5.7: For all different scenario variants, the maximum demand or production in tHM per year of depleted uranium, enrichment of uranium, plutonium and depleted uranium demand for MOX fuel production. N.B. peaks years (when full cores are loaded, see (see Figure 5.1)), are excluded.

| | DU production | SWU | Pu demand | DU demand |
|---|---|---|---|---|
| BORSSELE | 42 | 35 | 0.3 | 3.1 |
| ADAPT A (UOX) | 1365 | 1172 | 0.0 | 0.0 |
| ADAPT B (UOX/MOX) | 1152 | 989 | 2.0 | 21.9 |
| TRANSFORM A (UOX) | 1343 | 1153 | 0.0 | 0.0 |
| TRANSFORM B (UOX/MOX) | 1133 | 973 | 2.0 | 21.6 |

### 5.3.2 Back-end

Table 5.8 indicates the number of expected packages and the total mass of spent fuel per variant per scenario. Because the total energy production and burn-up has remained the same for both variants (of each of the scenarios), the mass of spent fuel (SNF) is the same for both variants of the TRANSFORM and ADAPT scenarios. The amount of separated reprocessed plutonium and uranium per scenario(variant) is shown in Table 5.9.

Table 5.8: Amount of high-level waste to be stored, with and without reprocessing, for all scenarios and variants.

| Scenario | SNF [tHM] | Without reprocessing | | With reprocessing | |
|---|---|---|---|---|---|
| | | Volume fuel assemblies [m³] | Volume CASTORs [m³] | Amount of CSD-Vs | Volume CSD-Vs [m³] |
| BORSSELE | 152 | - | - | 531 | 101 |
| ADAPT A (UOX) | 9209 | 3411 | 27086 | 16804 | 3193 |
| ADAPT B (UOX/MOX) | 9209 | 3411 | 27086 | 19753 | 3753 |
| TRANSFORM A (UOX) | 9060 | 3355 | 26646 | 16564 | 3147 |
| TRANSFORM B (UOX/MOX) | 9060 | 3355 | 26646 | 19466 | 3698 |

Table 5.9: Total amount of separated reprocessed plutonium and uranium [tHM] at the end of the calculation from the different scenarios and variants.

| Scenario | Separated plutonium | | Separated uranium | |
|---|---|---|---|---|
| | Variant A | Variant B | Variant A | Variant B |
| BORSSELE | 8.1 | | 91.4[43] | |
| ADAPT | 130.0 | 89.6 | 8550.6 | 8473.4 |
| TRANSFORM | 128.0 | 88.1 | 8410.3 | 8334.4 |

# 5.4 Scenario feasibility

In this Section, the results following from the assessment of the various scenarios considered in this analysis are discussed in terms of feasibility. This is done by comparing the calculated metrics against current capacities and future forecasts of nuclear industry developments. The main source of projections on the development of the international nuclear materials and services market is the World Nuclear Association (WNA) Nuclear Fuel Report (World Nuclear Association, 2023), but for Dutch national affairs and aspects related to particular companies or installations more specific primary sources are consulted. The WNA covers different scenarios: a lower, upper and reference scenario – the latter is used as comparison here. The aim of this section is to determine whether and if so, where, bottlenecks will arise in the nuclear fuel cycle, given the necessary boundary conditions of the various scenarios.

## 5.4.1 Front-end

*Uranium mining*

The current worldwide capacity for uranium mining is around 50,000 tU per year, which is less than the current demand (65,000 tU). This difference can be explained by the fact that uranium can easily be stored as a reserve resource, and these reserves are abundant. However, in the longer term, in addition to restarting inactive mines, new projects will have to be initiated to meet future demand (World Nuclear Association, 2023). Towards the end of the 21st century, new sources of uranium or alternative fuels (which require less or no

[43] Assuming uranium from both reprocessed ENU and ERU (re-enriched reprocessed uranium) gets separated.

natural uranium) will have to be put into use to meet the expected demand. Currently, the largest uranium-producing countries are Kazakhstan and Canada, which together account for more than half of the world's production capacity. In the future, however, the largest growth could come from Australia, which has more natural sources of uranium than Kazakhstan and Canada combined. At present, the production capacity to exploit these resources is lacking, but it could be developed in the future. It should be noted that identified resources typically refer to those that are recoverable for a specific price (typically < $130/kgU). This is a dynamic value, since these prices evolve over time (due to inflation and technological development). Exploration for new resources will also proceed at an accelerated rate if market forces make this a profitable activity. In addition to producing uranium from mining, sea water extraction might be another viable source in the future. Overall, it should not be expected that the overall global natural uranium resources will be depleted in this century, but increasing scarcity could increase its price. This is not directly a large concern, since uranium prices only have a marginal effect on the total nuclear energy cost profile.

Projections show that production from mining will increase to around 80,000 tU/year by 2040, with most of the growth coming from 'prospective mines' (potential projects that are not currently under development). At the same time, demand will also increase to around 130,000 tU/year in 2040, mainly driven by nuclear new construction in Asia. There will therefore be a gap between supply and demand of about 50,000 tU/year. This gap can be filled in various ways, such as by using existing government reserves and commercial inventories, but also materials from reprocessed spent fuel. Another possibility is to increase the production of existing mines, which often have a much higher capacity than is currently used. This gap between supply and demand makes it all the more interesting to use alternative fuel strategies. As covered in this analysis, MOX usage can reduce the demand for natural uranium. In addition, the use of reprocessed uranium (RepU), for example in c-ERU (compensated re-enriched uranium) as is currently used in Borssele, can result in a significantly lower demand for natural uranium.

For the various scenarios in this analysis, it appears that 200 to 400 ton of natural uranium per year will initially be needed in 2040, with a maximum of around 1200 to 1500 tU per year from 2050 onwards. The largest demand comes from ADAPT, variant A (UOX use only), while the lowest is TRANSFORM, variant B (UOX/MOX). The additional demand for uranium resulting from the Dutch scenarios comes on top of the expected strong growth in demand resulting from global nuclear new construction. Around 2050, Dutch reactors could account for between 0.9 – 1.2% of global demand.

*Uranium enrichment*

At present, the global enrichment capacity is 61,500 tSWU per year, of which 25,500 is in the Western countries (World Nuclear Association, 2023). Urenco has capacity in Europe for approximately 13,700 tonnes SWU per year. In response to the increased demand for enrichment, companies such as Urenco are working to increase their enrichment capacity. Thanks to the modular design of ultracentrifuges, it is easy for these companies to adjust their capacity in time. Towards 2040, global enrichment demand is expected to be around 100,000 tSWU per year, as is the case for natural uranium driven by the increasing amount of nuclear energy installed. In addition to enrichment using ultracentrifuges, a new, potentially more efficient technique is also being developed: laser enrichment (Snyder, 2016). This technique would also make it possible to re-enrich depleted uranium, which could increase the supply of unenriched uranium in addition to increasing the enrichment capacity.

There are two important parameters in the enrichment: the product and tails assay. In practical terms, the product assay is fixed (typically close to 5%), as this is given as a prerequisite for the requirements of the fuel. However, the tails assay (the enrichment of the depleted uranium) is variable. The larger the tails assay, the less enrichment (SWU) is needed, but the more natural uranium is needed, and vice versa. Choosing the tails assay is therefore a balance between the availability and price of natural uranium, and the availability and price of SWUs that depend on the production capacity and price (the latter is related to energy costs).

Reliable forecasts about enrichment capacity in the future are difficult to make, because they will be very market-driven. It is relatively unfavourable to have overcapacity in the short term, so enrichment plants will build capacity relatively late if the demand for enrichment starts to rise. The largest increase that is expected will be in China, to provide for its internal market. Urenco has announced that in 2027 the production capacity of their enrichment plant in Almelo will increase by 15%, through an increase in capacity of 750 tSWU per year (Urenco, sd).

The scenarios in this report require between 973 (TRANSFORM B) to 1172 (ADAPT A) tSWU per year. This will be 1.0 – 1.2% of global demand after 2050.

*Nuclear fuel production*
The fuel market is different from the raw materials market, because its production is very specific (i.e. focused on specific reactor (types)). The geographical location of manufacturers plays an important role in the accessibility and attractiveness for customers. The transport of nuclear fuel is logistically challenging, and preferably the transport distance is minimized. Therefore, the rest of this review will focus on European supply and demand. Within Europe, the demand for manufacturing for reloading will[44] increase slightly between now and 2040. There will first be a decrease because older reactors will be decommissioned, followed by an increase due to new construction. In addition to the installed capacity, fuel burnup is also a determining factor for the development of the demand for nuclear fuel. There is a trend in which reactors achieve an increasingly higher burnup with their nuclear fuel, which reduces the demand for nuclear fuel per unit (although the composition will be slightly different) (U.S. NRC, 2024).

Within Europe, there are a number of players active as designers and producers of nuclear fuel. Westinghouse (Sweden, UK) and Framatome (France, Germany) design and produce. Orano offers reprocesses and produces fuel (France, producer of MOX, among others). ENUSA (Spain) is licensed to produce Westinghouse PWR and GE Hitachi BWR nuclear fuel. Almost all of these producers have access to the entire fuel production process, including conversion, fuel pellet production and fuel element fabrication. ENUSA is an exception to this: they can produce fuel pellets and elements, but do not have the conversion capacity to convert $UF_6$ to $UO_2$.

Currently, the UOX fabrication capacity in Europe is almost 4000 tHM/year. Orano is (among various other services) the only MOX manufacturer in Europe, with a capacity of approximately 200 tHM/year. Orano will investigate the expansion of the production capacity by means of a new MOX factory, but no concrete plans have been announced yet (Orano, 2024). The demand for PWR fuel in Europe is expected to remain relatively stable, between 3000 - 4000 tHM/year. Our analysis shows that the demand for fuel from Dutch

[44] Reloading, between fuel cycles, requires a different type of fuel than for 'first cores' (i.e. the initial nuclear charge when a reactor is started).

reactors at the highest point is approximately 120 - 150 tHM/year, depending on the scenario, which will be a few percent of the European market. The variant with partial (15.6%) MOX use would result in a MOX demand of approximately 24 tHM/year in that scenario. The scenario variants in which only UOX is used are unlikely to run into capacity problems.

*Reprocessing*
Currently, spent fuel from the Borssele plant is reprocessed at the La Hague facility in France. This facility has a reprocessing capacity of 1700 tonnes/year, and as of 2020, handles around 1100 tonnes of SNF each year (Orano, 2025). It is the biggest reprocessing facility in the world, and the only one in Europe. The largest demand for reprocessing in the scenarios in this analysis, equal to the maximum fresh fuel demand, is around 150 tonnes/year.

### 5.4.2 Intermediate storage

*HLW and SNF*
In 2022, COVRA reported on an update of the current and expected inventory of radioactive waste in the Netherlands. Historical data from the production of radioactive waste have been extrapolated to the future, partly on the basis of a small selection of forecasts about the future Dutch nuclear fleet. The estimated number of packages (per unit of energy) in the inventory is lower than determined in this analysis. This may be because the contents of the waste containers sent from France to the Netherlands do not have to correspond to the contents of the spent that EPZ has sent from the Netherlands to La Hague. Another reason is the conservative value used for calculating actinides in the spent fuel. Both of these aspects have been discussed in Section 2.4.

All HLW packages will have to be stored in the HABOG. The HABOG has a limited storage capacity, but its modular design allows for successive expansions. In 2022, 110 $m^3$ of HLW was stored in the HABOG, and an expansion of 50 $m^3$ capacity for heat-producing waste was made in 2022. Depending on the scenario and the fuel cycle policy, between approximately 3100 (TRANSFORM, variant A) and 3800 (ADAPT, variant B) of HLW storage [$m^3$] will be required. In the reference scenario of the COVRA national radioactive waste inventory which takes into account, among other things, 80 years of 3.2 GW of additional installed capacity, a total of 3747 $m^3$ HLW is expected. In the most conservative scenario in this analysis (ADAPT variant B), where 3800 $m^3$ of storage capacity is needed, the equivalent of 76 of the recently executed HABOG 50 $m^3$ HLW-capacity expansions is necessary. At the highest waste production rate, from 2050 onwards, 63 $m^3$ of HLW will be produced per year, which means that more than one of the previously described expansions per year will be necessary. If the HABOG is to be expanded in this modular form, it would require a large storage footprint on the COVRA site[45]. However, the current HABOG storage bunkers are designed to be around half filled with spent fuel from research reactors, and half filled with vitrified waste containers. A more efficiently designed bunker containing only vitrified waste containers would mean the space requirement could be approximately halved.

In addition to the heat-producing packages with vitrified waste, the packages filed with compacted waste will also have to be stored in the HABOG. From the approximately 9000 tHM of SNF that is being reprocessed, 900 CSD-Cs will be produced with a total volume of 171 $m^3$. Non-heat-producing waste can be stored more compactly, and with a well-designed layout will take up less space than heat-producing waste.

[45] Satellite images show that the HABOG extension has dimensions of approximately 35 m x 15 m, so 525 $m^2$ per 50 $m^3$ of additional storage capacity will be needed. 525 $m^2$ multiplied by 76 expansions gives a total area of almost 4 hectares.

If a variant is chosen in which no reprocessing takes place, entire fuel assemblies will have to be stored. Exactly how much volume needs to be stored depends on how this is carried out, but with the CASTOR solution as discussed in this analysis, almost ten times the volume of HLW packages is needed, with a total volume of at most 27000 $m^3$. This concerns approximately 1000 CASTOR containers, which will occupy an area of approximately 6000 $m^2$ when stored in a square grid (but will in reality require around twice as much space to leave room for handling and inspection).

Regardless of the chosen spent fuel strategy, a point to note is that a sufficiently larger area for HLW storage is necessary.

*Depleted uranium storage*
The Dutch radioactive waste inventory report expects approximately 50,000 $m^3$ (Burggraaff, Welbergen, & Verhoef, 2022) of depleted uranium waste that will be stored in the VOG (verarmd uranium opslag gebouw) buildings (VOG-1 and VOG-2) in the Netherlands until 2120. The current analysis predicts that up to 82 kilotonnes of uranium, equivalent to about 9000 $m^3$ of $U_3O_8$, will be produced as a by-product of enrichment for Dutch reactor fuel. The main supply of depleted uranium to the VOG buildings at COVRA comes from the enrichment facility of Urenco (COVRA, 2024). This supply is disconnected from the number of reactors in the Netherlands, because Urenco operates internationally. In addition, the uranium for new NPPs in the Netherlands can be enriched in the Netherlands or in other countries. This means that the required storage capacity for depleted uranium at COVRA is not directly related to the construction of reactors in the Netherlands.

The depleted uranium is stored in cubic containers with a capacity of 3.5 $m^3$, stacked in columns of 4. If it is assumed that the ground area of the cube is 4 $m^2$ (Arcadis, NRG, 2013), this means that $(4 \times 3.5\ m^3)/4\ m^2 = 3.5\ m^3/m^2$ of storage volume per floor area can be achieved. The surface areas of the VOG and VOG-2 are approximately 5000 and 6000 $m^2$ (based on satellite images). VOG-1 (13 500 $m^3$ capacity) has been full since 2015, and VOG-2 (23 000 $m^3$ capacity) is roughly 20% full. Considering COVRA's prognosis of 50 000 $m^3$ depleted uranium and the potential additional amount of depleted uranium due to the Dutch reactors of around 10 000 $m^3$, approximately the equivalent of an additional VOG-2 building would be needed. However, as mentioned above, the depleted uranium supply is disconnected from the number of reactors in the Netherlands.

# 6 Conclusions and recommendations

In Chapter 1 eight research questions were formulated. Based on the analyses performed, the answers to these questions are presented in this Chapter. In Section 6.1 four research questions are answered on the basis of analyses with OPERA, the integrated energy system model for the Netherlands. Three research questions that were investigated with the European power system model COMPETES-TNO are answered in Section 6.2. Answers to the research question about the nuclear fuel cycle are given in Section 6.3. The answers to the research questions are summarized by means of short conclusions of the study. Finally, recommendations for further research are presented in Section 6.4.

Note that the present study is limited to an analysis of the impact of nuclear integration on the energy system and the nuclear fuel cycle. Not all possible impacts of a future energy supply for the Netherlands with and without nuclear energy have been investigated. For example, impacts with respect to radiation safety, security risks (e.g. in relation to geopolitical developments), environmental aspects (during the entire life cycle of a nuclear reactor), proliferation risks, etc. are outside the scope of this study. Recommendations for further research into these impacts are given in Section 6.4.

## 6.1 Conclusions integrated energy system analysis

The four questions investigated with the integrated energy system model OPERA are:
1. What will be the future electricity demand and the possible share of nuclear electricity in the electricity mix?
2. What effect does adding nuclear energy to the energy mix have on final energy use?
3. How will nuclear energy influence energy import dependence?
4. What effect does integrating nuclear energy have on the costs of the energy system?

The analyses were performed for two scenarios of the future Dutch energy system (ADAPT and TRANSFORM) by comparing the system in which new NPPs (large NPPs and SMRs) are integrated with an energy system in which this does not happen. In addition, what-if analyses were used to investigate sensitivities with regard to (i) the investment costs of nuclear energy, (ii) no constraints on the maximum capacity potentials of wind, solar and nuclear power generation, and (iii) changes in foreign electricity and hydrogen demand. Below are the answers to these research questions. First, briefly formulated as a conclusion, followed by an explanation.

**1a. When renewable energy is utilized nearly to its full potential and nuclear energy is added to the energy system, a greater share of electricity demand can be met.**
As part of the energy transition, heating and mobility – traditionally reliant on fossil fuels – are increasingly electrified. Additionally, there is growing demand for sustainable hydrogen, which can be produced using $CO_2$-free electricity. Compared to current electricity demand,

this results in a substantial increase in both the ADAPT and TRANSFORM scenarios. Due to more ambitious sustainability goals, the increase in electricity demand is greater in TRANSFORM than in ADAPT. In scenarios without new nuclear power plants (NPPs), the full potential of wind energy is utilized, along with a significant portion of solar energy potential. These maximum potentials are constrained by available spatial area and societal acceptance of renewable energy technologies. The introduction of nuclear energy adds a new source to the energy mix. Large-scale NPPs contribute additional electricity, complemented by output from SMRs. This enables the system to meet more electricity demand. Consequently, electricity demand in 2050 rises by 7% in TRANSFORM and by 14% in ADAPT compared to scenarios without new NPPs. Part of this electricity is used for hydrogen production or exported to neighboring countries. This makes the optimal production mix sensitive to changes in international electricity and hydrogen demand or supply. If more electricity or hydrogen is imported – or less is exported – the required domestic generation capacity decreases, which in turn affects the cost-optimal level of nuclear capacity.

**1b. With the deployment of four large NPPs (total 6 $GW_e$) and SMRs (total 2.1 $GW_e$), nuclear energy is projected to account for 10.5% (TRANSFORM) to 14.5% (ADAPT) of the electricity mix by 2050. In the absence of new NPPs, the 2050 electricity mix would rely almost entirely on renewable sources, primarily wind and solar.**
In these scenarios, nuclear energy is expected to generate between 56 TWh (ADAPT) and 59 TWh (TRANSFORM) of electricity in 2050. For comparison, in 2024 the existing Borssele NPP produced 3.4 TWh nuclear electricity, 2.8% of total electricity production. This plant is assumed to be decommissioned in 2043 following a 10-year Long Term Operation (LTO) extension. The contribution of SMRs to total nuclear electricity production remains modest (7% in ADAPT and 12% in TRANSFORM) since SMRs are primarily deployed for industrial process heat rather than electricity generation. Wind and solar remain the dominant sources of electricity. In scenarios with new NPPs, they account for 84% (ADAPT) and 88% (TRANSFORM) of the electricity mix in 2050. Without nuclear energy, these shares rise to 97% and 99%, respectively. In an integrated system optimization, large NPPs operate as baseload units and do not provide flexibility to accommodate fluctuations in wind and solar output. Some SMRs, however, do generate electricity during periods of low renewable supply. If nuclear capacity is reduced, its share in the electricity production mix declines accordingly. The cost-optimal level of nuclear deployment is sensitive to factors such as rising nuclear investment costs or shifts in international electricity and hydrogen demand. These dynamics influence the overall configuration of the energy system.

**2. Integrating nuclear energy into the energy system facilitates greater electrification of heat demand in buildings, expands hydrogen production via electrolysis, and enables the direct use of nuclear heat in industrial processes.**

*Built environment*
By providing additional electricity from nuclear power plants, it becomes possible to increase the use of electric heating in the built environment. As a result of cost optimization, heat demand rises partly due to reduced investment in home insulation. Additionally, more affordable technologies are used such as basic heat pumps or electric boilers, which lowers the efficiency of converting electricity into heat. However, the cost savings from reduced insulation measures and the use of less efficient heating technologies outweigh the additional costs of electricity.

*Hydrogen*
In a cost-optimized energy system, additional electricity from nuclear power enables increased hydrogen production through electrolysis. This surplus hydrogen is primarily used

to produce synthetic fuels for aviation and maritime transport (i.e., bunker fuels), reducing reliance on biofuels in these sectors.

*SMRs*

SMRs are expected to play a significant role in the future Dutch energy system, both in supplying industrial process heat and providing electricity to specific regions. SMRs are primarily deployed in four of the seven modeled regions: Limburg, Zeeland, South Holland, and North Netherlands. High-pressure (HP) steam SMRs are located in Limburg, Zeeland, and South Holland, while low-pressure (LP) steam SMRs are distributed across Limburg, South Holland, Zeeland, and North Netherlands. In the two baseline scenarios, Limburg and North Netherlands stand out with relatively high shares of their annual electricity consumption—ranging from 4.2% to 18.5%—being met by SMRs situated within those regions. By 2050, SMRs are projected to meet the majority of industrial heat demand in the 100–200 °C (LP) and 200–400 °C (HP) temperature ranges, particularly for sectors such as refining and chemicals. This replaces conventional technologies like waste gas boilers, electric boilers, biomass boilers, and electric heat pumps. In the ADAPT scenario, SMRs could supply up to 73% of heat demand in the 100–200 °C range and 55% in the 200–400 °C range by 2050. In the TRANSFORM scenario, these shares are slightly different: 69% for low-pressure and 57% for high-pressure heat supply.

The deployment of SMRs shows strong resilience to changes in assumptions and boundary conditions. Even when investment costs for SMRs are doubled, the total installed capacity only decreases by 36%. The lowest level of SMR deployment (approximately 50% below the baseline) occurs in a scenario where no constraints are placed on wind, solar, or nuclear generation capacity. This reduction is driven by both a decline in electricity generation from SMRs and increased use of alternative heat sources such as waste gas and electric heat pumps. The most notable difference between the baseline and what-if scenarios is the reduction in electricity output from SMRs. This suggests that the electricity generation role of SMRs is more sensitive to broader energy system conditions than their role in heat supply. In other words, under the assumed cost parameters for alternative heat technologies, SMRs remain a cost-effective solution for industrial heat provision.

**3a. An energy system that includes nuclear power shows reduced dependence on fossil fuels compared to a system without nuclear energy. However, the system does become more dependent on imported uranium.**

In both scenarios, fossil fuels, biomass, and uranium are imported, along with electricity and hydrogen (see 3b below). No other energy imports are assumed. The integration of nuclear energy leads to a decline in fossil fuel of approximately 16% in 2050 in both scenario's (note that fossil fuel use in ADAPT is substantial larger than in TRANSFORM), while biomass imports remain unchanged due to their assumed maximum levels. Adding nuclear energy increases the total primary energy supply by 13% in ADAPT and 14% in TRANSFORM by 2050. This increase is largely due to the relatively low efficiency of the nuclear steam cycle, meaning the rise in primary energy is significantly greater than the increase in final energy consumption. As a result, the share of fossil fuels in the total primary energy mix declines more sharply than the absolute volume.

Currently, fossil fuels account for over 80% of primary energy supply. In the ADAPT scenario, fossil energy remains part of the mix in 2050 due to the use of CCS and limited sustainability ambitions for feedstocks and bunker fuels. Without new nuclear capacity, fossil fuels make up 31% of the mix in ADAPT; with nuclear, this drops to 23%. In TRANSFORM, a small amount of oil remains in the system, resulting in a fossil share of 7% without nuclear and 5% with nuclear. If cost-optimal nuclear capacity is reduced due to changing assumptions or boundary conditions, the impact on fossil fuel dependency and uranium imports will also be smaller.

3b. **The development of new nuclear production capacity can significantly influence the exchange of electricity and hydrogen with neighboring countries.**
The Dutch energy system is interconnected with those of Germany, Belgium, Norway, the United Kingdom, and Denmark through a network of electricity interconnectors. These connections are expected to be strengthened in the future. Additionally, hydrogen trade is anticipated to expand via dedicated pipelines to Germany and Belgium, while ammonia imports continue through Dutch seaports. The integration of nuclear energy into the national energy mix may affect both the import and export dynamics of electricity and hydrogen.

*Electricity*
In the TRANSFORM scenario, the system is expected to become a net exporter of electricity from 2040 onwards, with annual exports ranging between 7 and 14 TWh. The presence or absence of new nuclear power plants has minimal impact on this outcome. In contrast, the ADAPT scenario shows a net import of electricity from 2040, ranging between 15 and 20 TWh. However, in a system without new nuclear power plants, the changes in ADAPT are more pronounced than in TRANSFORM: net imports decrease to 9 TWh or even shift to a net export of 2 TWh.

*Hydrogen*
In the TRANSFORM scenario, hydrogen is imported from 2040 onwards, with net annual imports ranging between 12 and 34 TWh. In contrast, the ADAPT scenario shows hydrogen exports in both 2030 (13 TWh) and 2050 (19 TWh), but a net import in 2040 (15 TWh). These shifts are influenced by price differences between the Netherlands and neighboring countries, as well as cost optimization within the Dutch energy system. While the integration of nuclear energy affects the volume of hydrogen flows, it does not significantly alter the overall pattern of net imports and exports in either scenario.

**4. In an integrated system model, energy scenarios that include nuclear power can result in lower overall system costs compared to scenarios without nuclear power. New nuclear power plants result in increased costs for electricity production, but this is more than offset by lower costs on the demand side of the energy system. However, the cost advantage is highly dependent on the broader context of each scenario and on technology choices made independently in each sector.**
Model analysis indicates that annual system costs are approximately 1.6% lower in ADAPT and 1.7% lower in TRANSFORM when new nuclear capacity is included. Yet, this benefit is sensitive to key assumptions. For instance, if nuclear investment costs rise, the cost advantage disappears. Similarly, changes in international electricity and hydrogen supply and demand can significantly affect the trade balance, influencing system costs.
In scenarios with nuclear capacity in addition to renewable electricity supply, electricity is more widely used across demand sectors. This leads in these cost optimized scenarios to the adoption of less energy-efficient but lower-cost technologies such as electric boilers instead of heat pumps, or air-source heat pumps instead of ground-source ones. Additionally, both scenarios show cost savings in building insulation when nuclear energy is included, as fewer investments are made in measures like home insulation. However, technology choices made in the end-user sector, whether or not influenced by energy policy, are made independently of those in electricity production. Another major factor influencing system costs is the shift in energy imports and exports, particularly hydrogen, and to a lesser extent, natural gas,

especially in ADAPT. In TRANSFORM, these shifts result in higher costs for systems with nuclear energy, whereas in ADAPT, they contribute to lower costs.

## 6.2 Conclusions energy market analysis

The following three questions have been addressed by means of the COMPETES-TNO analyses performed:

5. What is the impact of nuclear integration on the need for flexibility in the electricity system?
6. What are the consequences of nuclear integration on energy market prices?
7. How will NPPs be operated in the future electricity market, what limits the flexible operation of nuclear reactors and how can social and private (i.e. investor) costs and benefits be balanced?

**5. In scenarios without nuclear energy, the demand for system flexibility increases, primarily due to a higher share of solar PV. This greater need for short-term flexibility is addressed through expanded energy storage capacity.**
The analysis focused on two sources of flexibility: energy storage and hydrogen production via electrolysis. Despite the higher solar PV generation in non-nuclear scenarios, electrolysis capacity is actually lower than in comparable scenarios with nuclear energy. As a result, electrolysers contribute less to system flexibility. To compensate, non-nuclear scenarios (both ADAPT and TRANSFORM) rely more heavily on battery energy storage to meet the additional short-term flexibility requirements.

**6. Average electricity prices are lower when nuclear energy is part of the energy mix.**
Energy scenarios that include nuclear power tend to have lower volume-weighted average electricity prices compared to those without. This is primarily because NPPs have relatively low marginal costs, reducing the need to dispatch more expensive generation sources such as gas and hydrogen. These price differences also influence cross-border electricity trade. In scenarios without nuclear energy in the Netherlands, electricity imports and exports shift, which in turn affects market prices in neighboring countries. As a result, electricity prices in surrounding regions are slightly higher compared to scenarios where nuclear energy is part of the Dutch energy mix.

**7a. In an electricity market dominated by variable renewable sources like wind and solar, large NPPs operate as load-following technologies. Their annual dispatch ranges from approximately 5,500 hours in 2040 to 6,500 hours in 2050.**
Note that this is a different result than the analysis with an integrated system optimization (conclusion 1b).
The dispatch and profitability of the NPPs were assessed within an energy-only market, where revenues depend solely on electricity prices and production. In future scenarios with high shares of solar and wind, NPPs are dispatched when market prices exceed their variable production costs. These prices fluctuate significantly due to variations in electricity demand and renewable supply. Operational constraints are taken into account, such as ramp rates, minimum load levels, and limits on the number of ramp-up and ramp-down cycles. However, in some cases, the required minimum time between cycles is exceeded, slightly reducing the actual number of operating hours.

**7b. In an electricity market heavily reliant on wind and solar, and where revenues are solely derived from market prices and electricity production (i.e. an energy-only market), annual revenues for large NPPs are insufficient to cover capital and operational costs.**
By 2050, and based on model assumptions, projected financial shortfalls amount to

–€$_{2015}$23/MWh in ADAPT and –€$_{2015}$28/MWh in TRANSFORM (–€$_{2024}$30/MWh and –€$_{2024}$36/MWh, respectively), leading to substantial annual operating losses. With a projected output of 41 TWh from a large NPP in TRANSFORM 2050, the estimated financial shortfall under applied market assumptions could amount to approximately €$_{2015}$1.1 billion (€$_{2024}$ 1.4 billion) annually, indicating that policy instruments or support mechanisms will be necessary to ensure investment viability. This analysis does not capture all real world variables such as financing structures, project-specific risks, or future policy interventions.

## 6.3 Conclusions nuclear fuel cycle analysis

Based on the nuclear fuel cycle analysis performed, research question no. 8 can be answered:

8. What is the impact of the projected expansion of nuclear energy on the nuclear infrastructure in the Netherlands, i.e. on fuel supply and nuclear waste management?

The nuclear fuel cycle analysis was performed for the Long Term Operation (LTO) of the current Borssele NPP and new NPPs and SMRs in the energy scenarios ADAPT and TRANSFORM, with two alternative fuels: enriched natural uranium (UOX) fuel or a combination of UOX and mixed oxide (MOX) fuel, a mixture of depleted uranium and reprocessed plutonium.

**8a. Around 2050, Dutch reactors account for between 0.9 – 1.2% of the global demand for natural uranium**.
The additional demand for (enriched) uranium resulting from the Dutch newbuild NPPs scenarios coincides with the expected strong growth in demand resulting from global nuclear new construction. Similar figures also apply to enrichment and conversion. The increasing demand in the Netherlands will go hand in hand with a global trend towards more installed capacity. As a result, the production capacity for UOX-related front-end goods and services will also increase. With respect to uranium based products, no direct obstacles have been identified. There are uncertain forecasts for future expansion of MOX production capacity. However, given the current capacity, a partial MOX fuel cycle in which all the plutonium from spent UOX is reused seems plausible. The use of MOX fuel results in a reduction in the demand for natural uranium, enrichment and conversion, proportional to the fraction of MOX fuel used in the core.

**8b. Storage capacity is required for 3100 to 3800 m$^3$ of heat producing high level waste (HLW) and 171 m$^3$ of non-heat producing waste from reprocessing, depending on the scenario and fuel choices.**
Approximately 3100 m$^3$ (TRANSFORM, UOX fuel) and 3800 m$^3$ (ADAPT, mix of UOX and MOX fuel) is required for storage of heat producing HLW (CSD-V's), and 171 m$^3$ of non-heat producing HLW (CSD-C's). The existing storage capacity will have to be significantly expanded for this[46].

**8c. Use of MOX is more beneficial on the front-end**
For fuel cycles using MOX (thus involving reprocessing) less uranium mining and enrichment work is needed. If a variant is chosen in which no reprocessing takes place, entire fuel assemblies will have to be stored. Exactly how much volume needs to be stored depends on

[46] It should be noted that the volumes of waste that are to be stored have been assessed independently from COVRA. The results presented in this work are not representative of COVRA's own projections or views, and are only valid within the scope of the scenarios assessed using the assumptions and methodology mentioned in this work.

how the storage is carried out, but with the CASTOR solution as discussed in this analysis, almost ten times the volume of HLW packages is needed compared with scenarios with reprocessing. The scenario variants with reprocessing combined with use of MOX yield slightly more HLW packages than those without MOX use. When reprocessing is employed, significant amounts of separated uranium and plutonium are formed. Apart from usage in MOX fuel, these could also be utilized in advanced reactors that are not included in this analysis.

## 6.4 Recommendations

The previous sections addressed eight key research questions. However, some topics require additional research. Not all questions could be fully answered within the scope of the present study, and some fell outside the scope. Further research is recommended on the questions and topics listed below to deepen understanding and support future decision-making.

### Further research on the integration of nuclear energy into the electricity system

- Once it has been decided to build new nuclear power plants, with capacities that deviate from the cost-optimal capacity, what will be the share of nuclear energy in the future electricity mix. And how does this affect the deployment of renewable electricity production?
- What is the implications for grid reinforcement? Will large NPPs require additional grid upgrades, or could smaller modular reactors (SMRs), particularly those integrated into industry with heat supply, reduce the need for reinforcement? Additionally, when SMRs supply energy to industry, is a backup facility necessary, and what are the consequences for grid connection and reliability?
- To what extent can nuclear energy enhance the resilience of the Dutch energy system against weather-related variability (e.g., dunkelflaute) and disruptions in international energy trade?
- What impact can NPPs have on need for balancing reserves, such as Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), or manual Frequency Restoration Reserve (mFRR)? Can NPPs also contribute to these services, including black start capability?

### Research on spatial impact of NPPs

While nuclear power plants (NPPs) have a relatively small footprint in terms of energy produced per unit of land, they do impose specific spatial requirements. These include zoning regulations – such as maintaining a safe distance from residential areas – and access to cooling water, which may necessitate the use of cooling towers and additional space. For small modular reactors (SMRs), especially those intended for industrial use with co-generation of heat, proximity to the heat application site becomes a critical factor. The Netherlands currently has a location policy for large NPPs, but no dedicated policy exists for SMRs. Key questions for further exploration include:

- What are the spatial boundary conditions for deploying NPPs, particularly SMRs?
- How do these conditions affect the feasibility and selection of potential sites?

### Further research on costs and benefits of NPPs

- Accurate economic data on nuclear power plants (NPPs) is crucial for energy system and market analyses. Currently, there is significant uncertainty surrounding future investment costs. A key question remains: What will NPPs cost in the future? Reliable data is also essential for evaluating alternative technologies, particularly the costs and potential of flexibility options such as hydrogen production via electrolysis.

- This study applied specific capacity limits for nuclear energy: 6 GW for large NPPs and 2.1 GW for SMRs. These limits were often reached, suggesting that the economic optimum may lie beyond them. Since these constraints are not necessarily based on physical limitations, it may be worthwhile to explore scenarios without such restrictions.
- System studies can assess the impact of nuclear energy on national or societal costs, typically by identifying avoided costs. However, broader social benefits, such as energy security, resilience, and industrial development, are not fully captured. Further research is needed to quantify these benefits and compare them to the associated costs.
- System optimization models are not well-suited to assess the costs and benefits of NPPs from a private investor's perspective. Energy market models can help estimate potential revenues, including for SMRs with heat applications. To evaluate public support mechanisms (e.g., contracts for difference), a method is needed to assess private costs and revenues, incorporating future risks and uncertainties.
- A critical factor in the business case for NPPs is how investors and financiers manage financial risks. This affects interest rates on loans and required returns on investment. How do these risks compare to those associated with other technologies like offshore wind, solar PV, or electrolysers? What risk mitigation strategies are available, and to what extent can they reduce the cost of capital?

### Research into other impacts

While the system analysis conducted in the present study offers valuable insights into the role of nuclear energy in the future Dutch energy system and the nuclear infrastructure required, it does not capture all potential impacts. To fully assess the benefits and drawbacks of nuclear energy for Dutch society, a comprehensive impact analysis is recommended. Such an analysis should go beyond technical and economic considerations to include ecological implications, security risks (including those arising from geopolitical developments), and economic effects (such as labour market dynamics and regional development). A broad impact assessment would provide a more holistic perspective, supporting well-informed and balanced decision-making.

### Further research on SMRs with co-production of heat

- The present study examined SMRs co-producing heat and electricity at two temperature levels. Further research is needed into the potential for co-production at higher temperatures (above 400 °C) and for applications in district heating networks. Additionally, the feasibility of heat utilization from large NPPs, such as for heat networks, warrants investigation.
- What are the possibilities for heat utilization from high-temperature SMRs using alternative cooling methods such as gas, molten salt, or liquid metal?
- Innovations in industrial heat could either complement or compete with SMRs. Examples include industrial heat pumps and hybrid systems combining steam and electric heating, enabling temperatures above 400 °C. What implications do these technologies have for the role and competitiveness of SMRs?
- SMRs can supply both electricity and heat. When electricity is prioritized, how is the associated heat managed? What role can heat storage play in balancing fluctuating heat output? And what constraints do industrial heat applications impose on the flexible operation of SMRs?
- SMRs with heat utilization appear more cost-effective than large NPPs. Under what conditions can SMRs be deployed efficiently, both from a system-wide perspective and in terms of individual business cases? And when might such deployment not be viable?

### Research on hydrogen production with nuclear energy

This system study did not examine hydrogen production using small modular reactors (SMRs). Several important questions remain:

- Is hydrogen production using nuclear energy a cost-effective option from a system perspective? The answer depends on how nuclear compares to alternative hydrogen production methods, both domestically and internationally.
- How flexible is hydrogen production when coupled with NPPs? Electrolysis-based hydrogen production is a key flexibility option in the electricity system, especially when combined with hydrogen storage. A comparative system study is needed to evaluate nuclear-based hydrogen production alongside other options.

### Expanding scenario analysis for nuclear energy integration

The present study explored the integration of nuclear energy into the Dutch energy system using a limited set of scenarios and variants, each based on a small number of varying parameters and boundary conditions. To gain deeper insights, a more advanced approach – scenario space analysis – is recommended. Scenario space analysis allows for the variation of a much larger number of parameters (up to around 1,000 model runs), enabling the identification of tipping points and boundaries for the feasible deployment of nuclear energy. By exploring a broader range of combinations, this method can reveal critical thresholds and help map out viable pathways for integrating nuclear energy into the future energy system.

### Further research on the nuclear fuel cycle

Based on the results and conclusions of the nuclear fuel cycle analysis, some recommendations have been identified for future research:

- In scenarios where reprocessing is applied, there are always unused amounts of uranium and plutonium. These materials could be further exploited, for example by using re-enriched uranium in new UOX fuel or plutonium as fuel for advanced reactor fuel. A follow-up study in which advanced reactor fuels close the fuel cycle as much as possible would be interesting, as it could demonstrate a more efficient usage of natural resources and a minimization of high-level radioactive waste.
- An in-depth assessment of the implications for the final disposal of radiological waste in a deep geological repository would provide insight into the total life-cycle impact of different fuel cycle choices. By doing so, a more holistic (cradle-to-grave) view of the total implications would allow for a more informed decision-making process.

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# Appendix A
# Demand input parameters OPERA

The values for these demand developments for the ADAPT scenario have been taken from the Climate and Energy Outlook 2022

| Sector | Unit | ADAPT | | | | | TRANSFORM | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2030 | 2035 | 2040 | 2045[a] | 2050[a] | 2030 | 2035 | 2040 | 2045 | 2050 |
| Industry | | | | | | | | | | | |
| Steel production | Mtonne | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 6.48 | 6.21 | 5.94 | 5.67 | 5.4 |
| Ammonia production | Mtonne | 2.83 | 2.92 | 3.01 | 3.1 | 3.2 | 2.38 | 2.14 | 1.9 | 1.63 | 1.34 |
| Olefine production | Mtonne | 5.50 | 5.76 | 6.07 | 6.40 | 6.72 | 4.95 | 4.75 | 4.56 | 4.32 | 4.03 |
| Aromatics production | Mtonne | 4.37 | 4.57 | 4.82 | 5.08 | 5.34 | 3.98 | 3.81 | 3.64 | 3.44 | 3.20 |
| Methanol production | Mtonne | 0.51 | 0.53 | 0.55 | 0.57 | 0.59 | 0.46 | 0.44 | 0.41 | 0.39 | 0.36 |
| Chlorine production | Mtonne | 1.14 | 1.2 | 1.27 | 1.34 | 1.41 | 1.03 | 0.99 | 0.95 | 0.9 | 0.84 |
| Salt production | Mtonne | 8.22 | 8.6 | 9.09 | 9.6 | 10.11 | 7.39 | 7.09 | 6.82 | 6.48 | 6.06 |
| Glass production | Mtonne | 0.97 | 1 | 1.02 | 1.05 | 1.07 | 0.87 | 0.86 | 0.84 | 0.84 | 0.85 |
| Ceramic production | Mtonne | 3.04 | 3.04 | 3.05 | 3.05 | 3.06 | 2.73 | 2.62 | 2.51 | 2.46 | 2.41 |
| Non-energetic use other industries | PJ | 19.00 | 19.35 | 19.75 | 20.15 | 20.57 | 19.00 | 19.35 | 19.75 | 20.15 | 20.57 |
| Waste incineration | PJ | 29.37 | 29.37 | 29.35 | 29.37 | 29.37 | 62.49 | 54.68 | 46.87 | 29.29 | 15.62 |
| Mobility | | | | | | | | | | | |
| Passenger road traffic | Billion vehicle kilometres | 117 | 122.77 | 128.88 | 134.8 | 140.79 | 111.1 | 112.8 | 114.8 | 116.7 | 119.7 |
| Light freight traffic | Billion vehicle kilometres | 21.36 | 22.54 | 23.6 | 24.69 | 25.77 | 21.15 | 22.09 | 22.89 | 23.7 | 24.48 |
| Heavy freight traffic | Billion vehicle kilometres | 8.63 | 8.94 | 9.28 | 9.6 | 9.93 | 8.54 | 8.76 | 9 | 9.22 | 9.43 |
| Inland shipping | Billion vehicle kilometres | 53.84 | 55.27 | 56.7 | 58.13 | 59.55 | 54.38 | 56.38 | 58.4 | 60.45 | 62.53 |
| Bus transport | Billion vehicle kilometres | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 | 0.69 | 0.7 | 0.7 | 0.71 | 0.72 |
| Lubricant use | PJ | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |

[a] trend is extrapolated

| Sector | Unit | ADAPT | | | | | TRANSFORM | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2030 | 2035 | 2040 | 2045[a] | 2050[a] | 2030 | 2035 | 2040 | 2045 | 2050 |
| Energy demand for mobile equipment | | | | | | | | | | | |
| Agriculture | PJ | 15 | 15.6 | 15.19 | 15.19 | 15.19 | 11.25 | 9.79 | 9.01 | 8.82 | 8.63 |
| Industry | PJ | 25.5 | 23.9 | 13.68 | 21.87 | 20.84 | 22.95 | 19.72 | 10.26 | 14.76 | 12.5 |
| Service sector | PJ | 7.09 | 7.09 | 7.09 | 7.09 | 7.09 | 7.99 | 8.42 | 8.85 | 9.27 | 9.7 |
| Energy demand international transport | | | | | | | | | | | |
| International aviation | PJ | 159.3 | 168.31 | 178.35 | 186.24 | 194.16 | 137.7 | 145.4 | 153.1 | 160.8 | 170 |
| International shipping | PJ | 472.6 | 472.4 | 474.1 | 476.3 | 469.1 | 429.4 | 408.5 | 387.5 | 364 | 340.6 |
| Building stock | | | | | | | | | | | |
| Number of apartments | Million | 2.97 | 3.09 | 3.14 | 3.18 | 3.23 | 2.97 | 3.09 | 3.14 | 3.18 | 3.23 |
| Number of terraced houses | Million | 2.43 | 2.52 | 2.57 | 2.6 | 2.64 | 2.43 | 2.52 | 2.57 | 2.6 | 2.64 |
| Number of other homes | Million | 2.84 | 2.95 | 3 | 3.05 | 3.09 | 2.84 | 2.95 | 3 | 3.05 | 3.09 |
| Gross floor area education | Million $m^2$ | 32.19 | 31.5 | 30.83 | 30.16 | 29.5 | 32.19 | 31.5 | 30.83 | 30.16 | 29.5 |
| Gross floor area hospitals | Million $m^2$ | 21.24 | 23.38 | 25.86 | 28.48 | 31.1 | 21.24 | 23.38 | 25.86 | 28.48 | 31.1 |
| Gross floor area commercial buildings | Million $m^2$ | 173.9 | 184.19 | 195.14 | 206.42 | 217.7 | 173.9 | 184.2 | 195.1 | 206.4 | 217.7 |
| Gross floor area offices | Million $m^2$ | 68.89 | 69.56 | 70.01 | 70.77 | 71.45 | 72.34 | 74.78 | 77.11 | 79.62 | 82.16 |
| Gross floor area data centres | Million m2 | 1.62 | 2.05 | 2.59 | 3.30 | 4.19 | 1.62 | 2.05 | 2.59 | 3.30 | 4.19 |
| Gross floor area other service sector buildings | Million $m^2$ | 134.8 | 136.99 | 138.64 | 139.83 | 141.02 | 134.8 | 137 | 138.6 | 139.8 | 141 |
| Other heat demand | | | | | | | | | | | |
| Agriculture | PJ | 70.66 | 66.46 | 71.65 | 71.65 | 71.65 | 56.53 | 53.36 | 50.18 | 46.59 | 42.99 |
| Base metal – ferro | PJ | 10.22 | 19.01 | 9.218 | 9.06 | 8.901 | 8.41 | 8.08 | 7.61 | 7.13 | 6.67 |
| Base metal – non-ferro | PJ | 1.42 | 1.4 | 1.45 | 1.44 | 1.44 | 1.46 | 1.21 | 1.25 | 1.44 | 1.24 |
| Fertiliser industry | PJ | 6.24 | 12.02 | 12.81 | 12.16 | 13.78 | 10.25 | 8.6 | 9.19 | 7.04 | 6.33 |
| Chemical industry | PJ | 94.38 | 95.47 | 111.32 | 104.66 | 131.52 | 86.23 | 80.36 | 92.78 | 91.32 | 95.76 |
| Food and beverage industry | PJ | 40.6 | 37.65 | 38.55 | 37.95 | 38.26 | 40.6 | 34.97 | 38.68 | 34.97 | 38.03 |
| Other industry | PJ | 36.69 | 40.76 | 40.53 | 41.97 | 36.97 | 43.65 | 45.96 | 52.17 | 45.03 | 43.79 |
| Waste processing industry | PJ | 62.49 | 62.49 | 62.49 | 63.49 | 64.49 | 6.4 | 5.78 | 5.17 | 4.58 | 3.84 |
| Other fuel demand Transport | PJ | 23.98 | 23.65 | 23.29 | 22.66 | 22.86 | 37.79 | 34.43 | 27.29 | 30.91 | 28.68 |

[a] trend is extrapolated

| Sector | Unit | ADAPT | | | | | TRANSFORM | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2030 | 2035 | 2040 | 2045[a] | 2050[a] | 2030 | 2035 | 2040 | 2045 | 2050 |
| Other fuel demand Transport | PJ | 23.98 | 23.65 | 23.29 | 22.66 | 22.86 | 37.79 | 34.43 | 27.29 | 30.91 | 28.68 |
| (Other[b]) electricity demand | | | | | | | | | | | |
| Households | TWh | 19.58 | 20.14 | 20.65 | 21.23 | 21.83 | 19.58 | 20.14 | 20.65 | 21.23 | 21.83 |
| Service sector (incl. data centres) | TWh | 26.75 | 27.63 | 28.86 | 30.15 | 31.00 | 29.79 | 31.68 | 34.12 | 36.80 | 39.18 |
| Agriculture | TWh | 7.03 | 7.19 | 7.65 | 7.65 | 7.65 | 9.14 | 9.71 | 10.71 | 11.09 | 11.47 |
| Basis metal – ferro | TWh | 2.11 | 2.11 | 2.11 | 2.11 | 2.11 | 1.90 | 1.82 | 1.74 | 1.66 | 1.59 |
| Basis metal – non-ferro | TWh | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fertiliser industry | TWh | 0.36 | 0.10 | 0.0 | 0.0 | 0.0 | 0.30 | 0.07 | 0.0 | 0.0 | 0.0 |
| Chemical industry | TWh | 12.01 | 12.35 | 12.33 | 13.02 | 13.64 | 10.98 | 10.32 | 9.34 | 8.83 | 8.18 |
| Food and beverage industry | TWh | 10.57 | 10.21 | 10.52 | 10.38 | 10.35 | 10.57 | 10.21 | 10.52 | 10.38 | 10.35 |
| Other industry | TWh | 10.35 | 10.49 | 10.93 | 11.16 | 11.31 | 11.39 | 11.86 | 12.69 | 13.29 | 13.82 |
| Waste processing industry | TWh | 1.94 | 1.94 | 2.08 | 2.13 | 2.20 | 1.94 | 1.70 | 1.56 | 1.33 | 1.10 |
| Transport[b] | TWh | 1.95 | 2.01 | 2.07 | 2.13 | 2.20 | 1.97 | 2.05 | 2.14 | 2.22 | 2.31 |

[a] Electricity demand in addition to electrification of heat appliances and industrial processes, e.g. lighting, mechanical drives, etc.

[b] This concerns electricity demand for trains and trams.

# Appendix B
# Electricity and hydrogen demand for European countries

The electricity and hydrogen demand assumed for the European electricity system as input for the COMPETES-TNO model is summarised in the tables below for the different years and versions of TYNDP. For TYNDP-24 only data for 2040 and 2050 were used.

Table B.1: Electricity demand for European modelled countries in COMPETES-TNO for the year 2030 TYNDP-22.

| 2030 [TWh] | Conventional | EV | HP | Max. Potential Industrial Heat. |
|---|---|---|---|---|
| AT | 45.4 | 2.0 | 13.7 | 26.8 |
| BE | 49.8 | 2.7 | 13.1 | 36.8 |
| CZ | 35.5 | 1.7 | 6.4 | 23.9 |
| DE | 392.5 | 16.5 | 77.7 | 214.5 |
| DK | 34.6 | 3.1 | 8.9 | 8.9 |
| BT | 20.0 | 1.2 | 3.1 | 6.5 |
| ES | 169.4 | 9.2 | 34.4 | 71.3 |
| FI | 58.4 | 1.8 | 21.4 | 34.0 |
| FR | 289.6 | 20.5 | 85.0 | 130.8 |
| IE | 29.8 | 1.4 | 6.2 | 10.8 |
| IT | 191.8 | 12.8 | 39.3 | 95.2 |
| PL | 107.2 | 4.4 | 18.0 | 52.7 |
| PT | 34.8 | 2.6 | 5.8 | 13.2 |
| SE | 70.6 | 3.0 | 31.4 | 42.9 |
| SK | 17.2 | 0.9 | 3.0 | 10.9 |
| UK | 228.0 | 15.8 | 68.5 | 86.8 |
| BK | 209.0 | 9.1 | 31.8 | 76.4 |
| CH | 60.2 | 0.9 | 0.0 | 0.0 |
| NO | 172.5 | 0.4 | 0.0 | 0.0 |

Table B.2: Electricity demand for European modelled countries in COMPETES-TNO for the year 2040 TYNDP-22.

| 2040 [TWh] | Conventional | EV | HP | Max. Potential Industrial Heat. |
|---|---|---|---|---|
| AT | 53.4 | 4.4 | 15.4 | 27.7 |
| BE | 54.5 | 5.6 | 19.3 | 38.2 |
| CZ | 38.5 | 3.6 | 8.3 | 28.7 |
| DE | 426.0 | 45.0 | 99.4 | 224.3 |
| DK | 40.3 | 4.1 | 11.3 | 9.1 |
| BT | 19.7 | 2.6 | 3.9 | 6.7 |
| ES | 186.9 | 21.6 | 38.6 | 72.6 |
| FI | 75.3 | 4.1 | 22.7 | 36.5 |
| FR | 296.8 | 46.2 | 87.9 | 151.8 |
| IE | 33.4 | 3.1 | 7.8 | 10.9 |
| IT | 201.7 | 26.4 | 50.6 | 107.5 |
| PL | 117.2 | 11.5 | 22.8 | 55.9 |
| PT | 36.7 | 5.5 | 6.3 | 15.4 |
| SE | 75.2 | 6.4 | 31.8 | 43.1 |
| SK | 18.0 | 2.1 | 3.9 | 12.5 |
| UK | 283.2 | 56.5 | 95.6 | 91.0 |
| BK | 223.9 | 19.9 | 36.2 | 78.4 |
| CH | 68.3 | 1.7 | 0.0 | 0.0 |
| NO | 183.1 | 0.8 | 0.0 | 0.0 |

Table B.3: Electricity demand for European modelled countries in COMPETES-TNO for the year 2050 TYNDP -22.

| 2050 [TWh] | Conventional | EV | HP | Max. Potential Industrial Heat. |
|---|---|---|---|---|
| AT | 56.4 | 7.0 | 15.1 | 31.8 |
| BE | 62.2 | 8.5 | 21.4 | 41.6 |
| CZ | 44.0 | 5.4 | 9.5 | 28.6 |
| DE | 453.7 | 69.6 | 102.7 | 245.0 |
| DK | 43.9 | 5.1 | 12.4 | 9.8 |
| BT | 21.1 | 4.0 | 4.1 | 7.1 |
| ES | 222.1 | 27.3 | 38.3 | 75.1 |
| FI | 79.8 | 4.7 | 23.4 | 36.5 |
| FR | 309.1 | 65.7 | 75.7 | 175.6 |
| IE | 37.7 | 4.7 | 8.1 | 11.6 |
| IT | 224.0 | 49.9 | 55.2 | 109.9 |
| PL | 137.8 | 19.9 | 24.0 | 63.7 |
| PT | 40.1 | 7.0 | 6.4 | 17.1 |
| SE | 80.8 | 9.5 | 30.2 | 45.3 |
| SK | 20.4 | 3.3 | 4.1 | 16.6 |
| UK | 325.1 | 53.1 | 102.4 | 101.1 |
| BK | 246.7 | 30.9 | 36.5 | 85.1 |
| CH | 76.2 | 2.4 | 0.0 | 0.0 |
| NO | 193.1 | 2.6 | 0.0 | 0.0 |

Table B.4: Hydrogen demand for European modelled countries in COMPETES-TNO for the 2030-2050 TYNDP-22.

| [TWh] | 2030 | 2040 | 2050 |
|---|---|---|---|
| AT | 6.4 | 20.1 | 28.6 |
| BE | 6.5 | 47.3 | 77.7 |
| CZ | 7.1 | 26.4 | 32.2 |
| DE | 93.6 | 333.2 | 452.4 |
| DK | 1.5 | 7.7 | 15.2 |
| BT | 5.3 | 15.2 | 17.7 |
| ES | 11.6 | 72.3 | 122.1 |
| FI | 2.2 | 24.0 | 39.2 |
| FR | 22.0 | 46.3 | 80.6 |
| IE | 2.0 | 8.8 | 13.6 |
| IT | 38.4 | 148.5 | 197.2 |
| PL | 25.5 | 55.5 | 78.3 |
| PT | 2.1 | 8.5 | 17.0 |
| SE | 6.9 | 22.5 | 34.6 |
| SK | 3.5 | 9.9 | 13.2 |
| UK | 29.9 | 137.3 | 195.2 |
| BK | 29.6 | 100.4 | 139.9 |
| CH | 6.4 | 20.1 | 28.6 |
| NO | 6.9 | 22.5 | 34.6 |

Table B.5: Electricity demand for European modelled countries in COMPETES-TNO for the year 2040 TYNDP-24.

| 2040 [TWh] | Conventional | EV | HP | Max. Potential Industrial Heat. |
|---|---|---|---|---|
| AT | 67.3 | 9.5 | 12.7 | 20.7 |
| BE | 83.7 | 13.6 | 10.1 | 35.3 |
| CZ | 53.6 | 6.3 | 17.8 | 13.7 |
| DE | 524.9 | 86.8 | 77.7 | 141.9 |
| DK | 31.5 | 7.1 | 3.1 | 4.1 |
| BT | 20.6 | 4.0 | 4.2 | 4.6 |
| ES | 187.7 | 43.2 | 35.0 | 43.0 |
| FI | 76.7 | 6.9 | 22.9 | 31.5 |
| FR | 303.4 | 43.9 | 67.4 | 81.6 |
| IE | 57.9 | 5.8 | 10.4 | 4.0 |
| IT | 257.3 | 39.5 | 45.3 | 48.5 |
| PL | 127.9 | 19.1 | 24.0 | 34.2 |
| PT | 33.0 | 7.5 | 4.3 | 10.6 |
| SE | 81.0 | 9.4 | 28.6 | 70.1 |
| SK | 20.0 | 2.4 | 4.7 | 8.1 |
| UK | 201.0 | 0.0 | 95.6 | 91.0 |
| BK | 257.5 | 23.2 | 33.2 | 45.6 |
| CH | 72.3 | 0.0 | 0.0 | 0.0 |
| NO | 180.2 | 0.0 | 0.0 | 0.0 |

Table B.6: Electricity demand for European modelled countries in COMPETES-TNO for the year 2050 TYNDP-24.

| 2050 [TWh] | Conventional | EV | HP | Max. Potential Industrial Heat. |
|---|---|---|---|---|
| AT | 69.4 | 9.0 | 12.8 | 20.1 |
| BE | 90.0 | 20.8 | 12.2 | 39.7 |
| CZ | 57.2 | 10.7 | 17.0 | 15.1 |
| DE | 539.1 | 86.5 | 87.3 | 133.5 |
| DK | 27.4 | 7.4 | 1.6 | 3.2 |
| BT | 22.2 | 6.6 | 4.4 | 4.2 |
| ES | 181.8 | 62.5 | 45.5 | 57.1 |
| FI | 85.3 | 6.9 | 21.3 | 33.4 |
| FR | 303.1 | 46.8 | 62.1 | 88.7 |
| IE | 60.9 | 3.6 | 10.4 | 3.8 |
| IT | 269.4 | 60.6 | 55.1 | 51.7 |
| PL | 134.9 | 33.0 | 22.8 | 35.6 |
| PT | 34.4 | 9.8 | 3.3 | 9.7 |
| SE | 94.7 | 11.3 | 21.7 | 72.0 |
| SK | 22.3 | 4.2 | 4.4 | 8.3 |
| UK | 235.2 | 0.0 | 102.4 | 101.1 |
| BK | 263.4 | 39.7 | 32.0 | 46.3 |
| CH | 72.3 | 0.0 | 0.0 | 0.0 |
| NO | 180.2 | 0.0 | 0.0 | 0.0 |

Table B.7: Hydrogen demand for European modelled countries in COMPETES-TNO for the 2030-2050 TYNDP-22.

| [TWh] | 2040 | 2050 |
|---|---|---|
| AT | 30.2 | 33.2 |
| BE | 39.7 | 51.3 |
| CZ | 23.3 | 35.6 |
| DE | 313.2 | 372.8 |
| DK | 7.4 | 6.9 |
| BT | 12.9 | 19.9 |
| ES | 74.1 | 91.3 |
| FI | 25.9 | 33.8 |
| FR | 46.3 | 58.6 |
| IE | 6.0 | 7.4 |
| IT | 58.0 | 89.6 |
| PL | 54.8 | 85.8 |
| PT | 9.9 | 16.1 |
| SE | 37.0 | 51.5 |
| SK | 12.2 | 18.9 |
| UK | 134.0 | 161.6 |
| BK | 79.6 | 104.9 |
| CH | 30.2 | 33.2 |
| NO | 37.0 | 51.5 |

# Appendix C
# Fuel prices

| | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|
| | € 2015/GJ | | | | |
| Natural gas | 10.7 | 10.7 | 10.7 | 10.7 | 11.2 |
| Oil | 14.6 | 14.6 | 15.4 | 16.6 | 18.6 |
| Coal | 2.9 | 2.9 | 3.1 | 3.3 | 3.5 |
| Biomass, used cooking oil (UCO) | 16.2 | 16.2 | 16.2 | 16.2 | 16.2 |
| Biomass, woody, domestic | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 |
| Biomass, woody, import, cheap | 9.7 | 9.7 | 9.7 | 9.7 | 9.7 |
| Biomass, woody, import, expensive | 12.7 | 12.7 | 12.7 | 12.7 | 12.7 |
| Bio-oil | 8 | 8 | 8 | 8 | 8 |
| Bio-methanol | 27.3 | 25.4 | 45.9 | 35.7 | 66.4 |
| Bio-ethanol | 34.3 | 32.8 | 56.8 | 61.7 | 118.9 |
| Bio-kerosene | 33.8 | 29.9 | 41.1 | 23.2 | 45.8 |
| E-methanol | 230.8 | 218.0 | 205.3 | 192.5 | 179.8 |
| E-kerosene | 36.5 | 22.8 | 41.1 | 23.2 | 23.2 |
| Ammonia | 167.2 | 149.0 | 130.8 | 112.7 | 94.5 |

Appendix D

# Economic parameters nuclear power plants

For large NPPs, the CAPEX data from (KPMG, 2021) is taken as the reference for nuclear new investment costs, as it is tailored for the Dutch market. The average OCC from this source, which estimates a cost range of 4331-7290, is 5811 $€_{2015}$/kW. Other sources, as summarized in Table D.1, give the range 3510-9494 $€_{2015}$/kW, with an average of 6502 $€_{2015}$/kW.

According to KPMG, the Dutch nuclear market could benefit from previous first-of-a-kind (FOAK) projects in Europe, which supposes a reduction from FOAK to number-of-a-kind (NOAK) OCC costs of 20-30%. Given this, the costs assumed for the large NPPs are based on NOAK costs. The fixed costs and variable costs are obtained as an average of the sources above, resulting in 108 $€_{2015}$/kW/yr and 19 $€_{2015}$/MWh respectively.

The level of maturity for SMRs is still low, so we assume costs based as FOAK.  The average of (Steigerwald, Weibezahn, Slowik, & von Hirschhausen, 2023) SMR costs based on BWR/PWR, which results in an average excluding the extremely high value 28921 $€_{2015}$/kW, results in the 6776 $€_{2015}$/kW. This is within the range of other sources, See Table D.2. For fixed and variable costs, we take the average between the SMR BWR and PWR of the same source, resulting in 124 $€_{2015}$/kW/yr and 20 $€_{2015}$/MWh (incl. fuel costs), respectively.

For this study, the cost data assumptions used for the two nuclear reactor types are shown in Table D.3.

Table D.1: Literature overview of economic parameters for large NPPs (TNO, 2018c), (IEA & NEA, 2020), (IEA, 2023), (European Commission, 2023), (KPMG, 2021), (Witteveen en Bos, 2022), (Ingersoll, Gogan, Herter, & Foss, 2020), (Stewart & Shirvan, 2022), (Rothwell, 2022)

| | TNO (2018c) | IEA/NEA (2020) | IEA (2023) | KPMG (2021) | Witteveen en Bos (2022) | Ingersoll et al. (2020) | Stewart & Shirvan (2022) | EIA (2023) | Rothwell (2022) |
|---|---|---|---|---|---|---|---|---|---|
| Country/Region | OECD Europe | OECD Europe | Europe | Europe | Europe | Europe | - | US | Europe |
| Reactor Generation/Type | Gen III | Gen III | Gen III+/Gen IV | Gen III+ NOAK | EPR | Gen III PWR | Gen III+ PWR | LWR | Gen III EPR |
| Reference capacity ($MW_e$) | 1600 | 950-1650 | - | | 1600 | - | 1144 | 2156 | - |
| Overnight Capital Cost (2015€/kW) | 3510-7100 | 2959-9494 | 3700-5426 | 4331-7290 | 4666 | 9249 | 6449 | 6660 | 8342-9461 |
| Fixed O&M (2015€/kW/yr) | 50-160 | 2-217 | - | - | 87 | - | - | 117 | 102 |
| Variable O&M (2015€/MWh) | 2.5-11.44 | 11.1-16.3 | 30 | - | 2.5 | 27.8 | - | 2.3 | 16 |
| Fuel costs (2015€/MWh) | 5.3-9.1 | 10.6 | - | 3.8-11.6 | 7.9 | 7.8 | - | - | - |
| Economic lifetime | 60 | 60 | 60 | - | 60 | - | - | - | 60 |

Table D.2: Literature overview of economic parameters for SMRs (TNO, 2018d), (Stewart & Shirvan, 2022), (Moon & Kim, 2020), (Witteveen en Bos, 2022), (Ingersoll, Gogan, Herter, & Foss, 2020), (Steigerwald, Weibezahn, Slowik, & von Hirschhausen, 2023), (KPMG, 2021)

| | TNO (2018d) | Stewart & Shirvan (2022) | Moon & Kim (2020) | Witteveen en Bos (2022) | Ingersoll et al. (2020) | EIA (2023) | Steigerwald et al (2023) | | | | | KPMG (2021) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Country/Region | - | - | - | - | - | US | - | | | | | - |
| Reactor Generation/Type | SMR LWR | SMR Multi-module | SMR | SMR | SMR LWR | | SMR BWR | SMR PWR | SMR HTR | SMR SFR | SMR MSR | SMR Generation III+ |
| Reference capacity (MW$_e$) | 225 | 685 | - | - | - | 600 | - | - | - | - | - | 300 |
| Overnight Capital Cost (2015€/kW) | 3740-7280 | 5699 | 4676-12793 | 2616 | 6017 | 6500 | 2878 | 4490-28921 | 2163-5454 | 6299-24135 | 2432-7198 | 4041-9398 |
| Fixed O&M (2015€/kW/yr) | 70-150 | - | - | 174 | | 91.6 | 154 | 156 | 156 | 146 | 139 | - |
| Variable O&M (2015€/MWh) | - | - | - | 2.5 | 31.2 | 2.9 | 2.5 | | | | | - |
| Fuel costs (2015€/MWh) | - | - | - | - | 7.8 | - | 31.5 | 6.6 | 14.9 | 83.2 | 31.5 | - |
| Economic lifetime | 60 | - | - | 60 | - | - | 60 | 40-60 | 40-60 | 30-60 | 30-60 | - |

Table D.3: Cost parameters assumptions for the two nuclear reactor types used in this study (expressed in $€_{2015}$)

| | Large NPP | SMR |
|---|---|---|
| Overnight Capital Cost (inc. financial costs)[47] (€/kW) | 2030: 5811<br>2040: 5404<br>2050: 4998 | 2030: 6776<br>2040: 6301<br>2050: 5827 |
| Fixed O&M (€/kW) | 108 | 124 |
| Variable O&M (incl. fuel costs) (€/MWh) | 19 | 20 |

However, it is important to note the high level of uncertainty of these costs. Currently, the cost uncertainty of a NPP is one of the main challenges that hinders further nuclear newbuild. The estimated capital costs, as well as the operation and maintenance (O&M) costs vary considerably in the literature (see Table D.1 and Table D.2). The reactor's type and size considered, as well as the country or region where the NPP project is developed play a fundamental role. The economies of scale and knowledge and manufacturing base for Western countries have been lagging compared to Eastern countries such as Russia and China, which have surpassed in terms of construction time and costs on expanding their nuclear fleet compared to Europe or the US over the last decades. Additionally, easier licensing processes, cheaper labor and lower public resistance increments the differences between the West and the East.

The range of capital costs due to economies of scale can be seen when comparing projected costs of FOAK to a NOAK plant. The FOAK tends to be 30% more expensive than the NOAK (Gamboa Palacios & Jansen, 2018). More recently, (Stewart & Shirvan, 2022) investigated the NOAK effect for a $10^{th}$ unit of AP1000 NPP in the US, resulting in reducing the OCC by halve. Additionally, the construction time and the effect of financing during this period can influence greatly the total investment costs. ETI (2020) showed this effect assuming a 7% discount rate by comparing a 4 year construction time against 10 year construction time. The result is an increase of almost double of the total compounded OCC. Also (NEA, 2020) gives some guidance on the effect of financial costs, which can make up more than 20% of total investment costs per $kW_e$, especially for projects in OECD countries.

Regarding the decommissioning costs, understood as the dismantling of the plant, and returning it to a greenfield, (NEA, 2020) assumes relatively low decommissioning costs considering the overall nuclear production costs over the typical 60 year lifetime of recent nuclear designs, i.e. around 0.1% of these total generation costs. In terms of initial capital costs, (World Nucelar Association, 2024) gives another figure, with around 9-15% of the initial investment. Real decommissioning costs are difficult to obtain, but (KPMG, 2021) provides a range for decommissioning costs in Europe, from a minimum of 0.2M€/MW to 1.4 M€/MW, where the decommissioning process is estimated to take up to 20 years.

The most recent nuclear projects in Western Europe have faced very significant schedule delays and cost overruns compared to the projected targets. One of the main delay drivers was lack of design maturity (NEA, 2020). In Table D.4 the projected capital costs and expected year of commissioning of some NPP projects are shown compared to the actual or most recent projection. Considering the observed trend, the projected capital costs have increased considerably compared to what was provisioned in the beginning of the projects. However, these experiences can also reduce uncertainty through learned knowledge for

[47] The reduction of costs towards 2050 are based on a 14% cost reduction (Gamboa Palacios & Jansen, 2018).

future nuclear projects, especially if it is the same experienced responsible project management, and through stability in regulation, design maturity and series effect (IEA & NEA, 2020).

According to (KPMG, 2021), it is expected that Generation III+ reactors costs will be reduced around 20-30%, thanks to the proven maturity of the designs, the reduction in repetition of activities, such as licensing or safety tests for a second nuclear reactor and the lessons learnt from the first Generation III+ projects in Europe, which could lead to fewer delays. However, historical data from nuclear plants shows that this learning effect has not translated into lower costs, or that additional costs have surpassed the learning effect (Haas, Sayer, Ajanovic, & Auer, 2022) (Grubler, 2010).

Table D.4: Projected OCC and commissioning date for recent European nuclear projects as of June 2024. OCC data adapted to 2015 € from (Rothwell, 2022).

| | Projected OCC ($€_{2015}$/kW) | Actual/Most updated OCC ($€_{2015}$/kW) | Projected commissioning time | Actual/Most updated commissioning time | Delayed time |
|---|---|---|---|---|---|
| Oilkiluoto-3 (Finland EPR) | 6076 | 8689 | 2009 | 2022 | 12 years |
| Flamanville 3 (France EPR) | 6287 | 10519 | 2013 | 2024 | 11 years |
| Hinkley Point C (UK EPR) | 7532 | ~13100 - 14400 [a] | 2017 | 2027 | 10 years |

[a] Latest estimation 31-34 2015 B£ using exchange rate 1.377 (Hinkley Point C Update, 2024)

The construction time is estimated to be between 4 to 10 years for a conventional PWR NPP (Ingersoll, Gogan, Herter, & Foss, 2020), but this is not considering the delays of the latest nuclear projects. However, according to (KPMG, 2021) and (Scheepers, Haas, Roelofs, Jeeninga, & Gerdes, 2020), the construction time for proven Generation III+ designs in Europe can be achieved between 8 to 10 years.

Additionally to new-built nuclear, there is the lifetime extension of already existing large NPPs. The so called long-term operation (LTO) of NPP requires additional costs due to upgrade of refurbishments of equipment and the labor and indirect costs that this implies. The LTO procedure is very project-specific, but presents itself as the most economical option, with the OCC of this procedure ranging from 450-950 2018$/kW, potentially extending the lifetime of reactors towards 80 years (IEA & NEA, 2020).

Small Modular Reactors (SMRs) are characterized by having a power output compromised between 50 $MW_e$ and 500 $MW_e$, and their potential to be built in series, resulting in potential lower production costs (IEA & NEA, 2020). The most mature type of SMR is based on the Light Water Reactor (LWR) technology. Other new advanced generation IV SMRs are High Temperature Gas Reactors (HTGRs), Liquid Metal Cool-Fast Reactors (LMCFRs) and Molten Salt Reactors (MSRs) (Scheepers, Haas, Roelofs, Jeeninga, & Gerdes, 2020). As of 2024, there are only a few operational SMR designs, all located in the East: Russia and China. Some other SMR design examples in the West are the NuScale in the US or the CAREM reactor in Argentina, which are expected to begin operation in the 2020s, given a Technology Level Readiness (TRL) of 4-7 (IEA, 2023). The construction time and labor necessary for SMRs, and thus the construction costs of this technology are considered to be lower compared to a conventional NPP, with lower risk of cost overruns. This reduction in costs is mainly due to the modularity of SMRs, which allows to incorporate factory-assembled components, reducing field labor, and making easier the capacity expansion. This advantage is balanced off when considering the lack of economies of scale and the FOAK-characterized technology status. The construction time for SMR generation III+ is estimated at 3 to 5 years (Scheepers, Haas, Roelofs, Jeeninga, & Gerdes, 2020). However, the licensing framework is not expected to be readily available before 2027-2033 (KPMG, 2021). Given this, the time projection for SMRs to become operational is considered to be from 2040 onwards.

Given the high uncertainty of the costs for nuclear, a sensitivity case exploring a higher OCC is considered, doubling the investment costs of the base case, resulting in the following costs assumptions, in line with the current costs escalations seen in recent European nuclear projects:

Table D.5: Cost parameters assumptions for accounting higher costs uncertainty. Expressed in €$_{2015}$.

| | Large NPP LWR | SMR LWR |
|---|---|---|
| Overnight Capital Cost (incl. financial costs) (€/kW) | 2030: 11622<br>2050: 9996 | 2030: 13552<br>2050: 11654 |

Appendix E

# Nuclide inventory of fuel after burnup

Table E.1 shows the activity immediately after the fuel comes out of the core, per ton of heavy metal (tHM). In the case of Borssele, there is a one-year decay period. For each scenario, the required tonnage of waste has been calculated and based on Table E.1 it is determined what the activity, decay heat, etc. are over time,

Table E.1: Mass fractions in the inventory of the various fuel burnt-outs, in tonnes per tonne of heavy metal (t/tHM).

| Nuclide | LWR | SMR | LWR-MOX | SMR-MOX | Borssele (ENU) |
|---|---|---|---|---|---|
| U-232 | 8.93E-12 | 4.17E-12 | 2.21E-10 | 1.76E-10 | 0.00E+00 |
| U-233 | 2.14E-09 | 2.17E-09 | 1.94E-09 | 1.56E-09 | 0.00E+00 |
| U-234 | 7.84E-06 | 5.33E-06 | 6.97E-05 | 6.25E-05 | 2.30E-04 |
| U-235 | 1.03E-02 | 1.43E-02 | 1.05E-03 | 1.23E-03 | 1.27E-02 |
| U-236 | 6.56E-03 | 6.11E-03 | 2.89E-04 | 2.56E-04 | 0.00E+00 |
| U-237 | 1.11E-05 | 1.00E-05 | 1.83E-06 | 1.74E-06 | 9.69E-06 |
| U-238 | 9.10E-01 | 9.19E-01 | 8.74E-01 | 8.80E-01 | 9.31E-01 |
| U-240 | 9.18E-11 | 8.08E-11 | 6.40E-11 | 5.90E-11 | 0.00E+00 |
| Pu-236 | 3.25E-11 | 1.65E-11 | 3.45E-10 | 3.11E-10 | 0.00E+00 |
| Pu-237 | 8.48E-10 | 4.92E-10 | 5.10E-09 | 4.81E-09 | 1.06E-10 |
| Pu-238 | 4.60E-04 | 2.86E-04 | 2.12E-03 | 2.04E-03 | 3.36E-04 |
| Pu-239 | 7.78E-03 | 7.58E-03 | 2.50E-02 | 2.83E-02 | 5.25E-03 |
| Pu-240 | 3.17E-03 | 2.68E-03 | 1.85E-02 | 1.99E-02 | 2.72E-03 |
| Pu-241 | 2.18E-03 | 1.86E-03 | 1.06E-02 | 1.09E-02 | 1.42E-03 |
| Pu-242 | 9.13E-04 | 6.04E-04 | 6.77E-03 | 6.63E-03 | 1.12E-03 |
| Pu-243 | 1.84E-07 | 1.21E-07 | 6.65E-07 | 6.38E-07 | 1.25E-11 |
| Pu-244 | 7.04E-08 | 3.12E-08 | 7.88E-07 | 5.75E-07 | 0.00E+00 |
| Pu-246 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Np-235 | 2.61E-11 | 1.65E-11 | 1.16E-11 | 7.64E-12 | 0.00E+00 |
| Np-236 | 5.75E-09 | 4.18E-09 | 3.39E-09 | 2.64E-09 | 0.00E+00 |
| Np-237 | 8.93E-04 | 7.07E-04 | 2.16E-04 | 1.83E-04 | 0.00E+00 |
| Np-239 | 7.35E-05 | 6.92E-05 | 6.35E-05 | 6.13E-05 | 4.39E-05 |
| Am-241 | 1.10E-04 | 8.67E-05 | 1.27E-03 | 1.23E-03 | 4.76E-05 |
| Am-242m | 1.69E-06 | 1.30E-06 | 2.64E-05 | 2.47E-05 | 5.38E-07 |

| Nuclide | LWR | SMR | LWR-MOX | SMR-MOX | Borssele (ENU) |
|---|---|---|---|---|---|
| Am-243 | 2.44E-04 | 1.36E-04 | 2.11E-03 | 1.88E-03 | 2.75E-04 |
| Am-246 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Cm-242 | 3.54E-05 | 2.46E-05 | 2.06E-04 | 1.80E-04 | 2.74E-05 |
| Cm-243 | 1.07E-06 | 6.08E-07 | 9.01E-06 | 6.68E-06 | 8.34E-07 |
| Cm-244 | 1.11E-04 | 4.80E-05 | 1.41E-03 | 1.04E-03 | 1.38E-04 |
| Cm-245 | 9.43E-06 | 3.40E-06 | 2.05E-04 | 1.33E-04 | 6.22E-06 |
| Cm-246 | 9.21E-07 | 2.44E-07 | 1.54E-05 | 7.41E-06 | 1.87E-06 |
| Cm-247 | 1.68E-08 | 3.47E-09 | 4.19E-07 | 1.63E-07 | 0.00E+00 |
| Cm-248 | 1.28E-09 | 2.05E-10 | 2.97E-08 | 9.11E-09 | 0.00E+00 |
| Cm-250 | 1.97E-16 | 2.25E-17 | 5.83E-15 | 1.37E-15 | 0.00E+00 |
| Cs-134 | 2.27E-04 | 1.67E-04 | 2.13E-04 | 1.60E-04 | 2.83E-04 |
| Cs-135 | 9.40E-04 | 7.82E-04 | 1.64E-03 | 1.38E-03 | 3.90E-04 |
| Cs-137 | 1.95E-03 | 1.61E-03 | 1.98E-03 | 1.64E-03 | 2.26E-03 |
| Sb-125 | 1.31E-05 | 1.13E-05 | 1.77E-05 | 1.63E-05 | 8.60E-06 |
| Sn-126 | 3.78E-05 | 2.95E-05 | 5.60E-05 | 4.61E-05 | 0.00E+00 |
| Pm-147 | 2.03E-04 | 2.02E-04 | 2.03E-04 | 1.98E-04 | 2.12E-04 |
| Ce-144 | 2.91E-04 | 2.98E-04 | 2.54E-04 | 2.52E-04 | 3.86E-04 |
| Eu-154 | 4.55E-05 | 3.45E-05 | 9.04E-05 | 6.74E-05 | 7.04E-05 |
| Eu-155 | 1.46E-05 | 1.10E-05 | 2.22E-05 | 1.69E-05 | 1.70E-05 |
| Sm-151 | 2.01E-05 | 1.87E-05 | 5.18E-05 | 5.20E-05 | 1.03E-05 |
| I-129 | 2.59E-04 | 2.06E-04 | 3.60E-04 | 2.98E-04 | 2.04E-04 |
| Kr-85 | 3.65E-05 | 3.24E-05 | 2.06E-05 | 1.75E-05 | 6.63E-06 |
| Se-79 | 7.64E-06 | 6.46E-06 | 6.79E-06 | 5.68E-06 | 0.00E+00 |
| Zr-93 | 1.14E-03 | 9.61E-04 | 7.97E-04 | 6.57E-04 | 8.47E-04 |
| Nb-94 | 2.06E-09 | 1.58E-09 | 3.40E-09 | 2.84E-09 | 1.38E-09 |
| Tc-99 | 1.25E-03 | 1.06E-03 | 1.23E-03 | 1.04E-03 | 1.37E-03 |
| Pd-107 | 3.75E-04 | 2.75E-04 | 8.22E-04 | 6.79E-04 | 0.00E+00 |
| Ru-106 | 1.75E-04 | 1.49E-04 | 2.80E-04 | 2.73E-04 | 1.35E-04 |
| Ag-110m | 1.19E-06 | 8.17E-07 | 2.59E-06 | 2.13E-06 | 1.40E-06 |
| Sr-90 | 8.30E-04 | 7.23E-04 | 4.19E-04 | 3.49E-04 | 9.27E-04 |

Appendix F

# Calculation methodology and parametrization nuclear fuel cycle

The method to arrive at the results is as follows:

- Through the equations from below the amount of uranium required per year, per reactor has been determined. It also determines how much waste is produced per year (a 'batch').
- Via the nuclide vector given in Appendix E the mass of different nuclides in the waste is determined, per reactor, depending on the fuel used by this reactor.
- Using equations for radionuclide decay, the decay over time was tracked per batch.
- A cooling period of 5 years has been assumed in case a batch can be reprocessed. The batches are processed together (i.e. nuclides in packages can come from multiple batches, as is also the case with real reprocessing processes).
- With the limits from Table 2.8 the number of packages per round of reprocessing is calculated, as well as the amount of separated uranium (REPU) and Pu (for later use in MOX). The composition of nuclides are given for the reprocessed waste, REPU, separated Pu and unprocessed waste.

These steps were performed with a Python program, which includes functions for decay, reprocessing, and mass flows. In Appendix G, a code validation is presented.

*Uranium (UOX)*

Here the formulas are introduced that can be used to calculate the required uranium per reactor. As a starting point, we take the following variables:

- $P_e$ electrical power [MWe]
- $\eta_{th}$ Thermal efficiency [-]
- $g$ Capacity factor [-]
- $B$ Fuel burn-up [MWd/kg]

The mass of spent fuel per year $M_p$ [kg/yr] can then be calculated as follows:

$$M_p = \frac{g\, P_e\, 365.25\frac{d}{yr}}{\eta_{th}\, B}$$

We now assume that all mass is uranium. The weight of natural uranium per year $M_f$ [kg/yr] can then be calculated with the fuel enrichment $C_p$ (here 4.9%), natural enrichment $C_p$ (0.72%) and the enrichment of the depleted uranium $C_t$ (often 0.25%):

$$M_f = \frac{C_p - C_t}{C_f - C_t} M_p$$

The mass of depleted uranium, by mass conservation, is then $M_t = M_f - M_p$. The amount of $SWU$ [kg/yr] (a degree of work required for enrichment) can be calculated as follows (Lamarsh, page 203, 2001):

$$v(C) = (2C - 1)\ln\left(C/(1 - C)\right)$$

$$SWU = M_P v(C_p) + M_t v(C_t) - M_f v(C_f)$$

With $v(C)$ the "value function". With these formulas, an estimate can be made of the mass balance. Table F.1 shows the estimated consumption of uranium using the above formulas for the reactors with specifications of Table 2.9 (and 4.9% enrichment).

Table F.1: Estimation of uranium consumption by reactor type

| Reactor | Enriched uranium [tHM/yr] | Natural uranium [tHM/yr] | SWU [ton/yr] |
|---|---|---|---|
| LWR (1500 MWe) | 24.90 | 246.4 | 190.1 |
| SMR (150 MWe) | 3.22 | 31.9 | 24.6 |

*Plutonium (MOX)*

With MOX Fuel, the amount of fuel used per year is calculated in the same way as with UOX. The amount of plutonium required can be calculated as follows:

$$M_{Pu_{fiss}} = M_{Pu-239} + M_{Pu-241} = C_{MOX} M_p$$

With $M_{Pu_{fiss}}$ the required amount of fissile plutonium, $M_{Pu-239}$ the mass of Pu-239, $M_{Pu-241}$ the mass of Pu-241 and $C_{MOX}$ the mass fraction of fissile plutonium in the spent fuel. With an assumed enrichment rate of 8.4% Pu (equal to the MOX used in Borssele), an estimate can then be made of the required amount of plutonium per reactor (see Table F.3). The maximum fraction of MOX that can be used in a reactor that reuses its own plutonium once, can be derived by solving the follow mass balances:

$$M_{Pu_{fiss},given} = P_{UOX} c$$

$$M_{Pu_{fiss},needed} = P_{MOX} f$$

With $M_{Pu_{fiss},given}$ the fraction of fissile plutonium produced by a UOX reactor, :$P_{UOX}$ the power of the UOX reactor (thermal) and :$c$ a time-dependent constant determined by the composition of the processed fuel, cooling time and the efficiency of reprocessing. $M_{Pu_{fiss},needed}$ is the required fissile Pu mass for the MOX reactor(s), t$P_{MOX}$ is the power of the MOX reactor(s) with $f$ the mass fraction of the fissile Pu in the MOX. If we solve the equation $M_{Pu_{fiss},needed} = M_{Pu_{fiss},given}$ we get

$$max\ MOX\ fraction = \frac{M_{Pu_{fiss},needed}}{M_{Pu_{fiss},needed} + M_{Pu_{fiss},given}} = \frac{c}{c+f}$$

Table F.3 provides the results for the mass flows for the specifications of the LWR and SMR, and the calculated maximum fraction of MOX.

Table F.2: Estimation of plutonium required per reactor type.

| Reactor | MOX fuel [tHM/yr] | Fissile PU [tHM/yr] | DU [tHM/yr] | Fissile Pu produced in case of OTC [tHM/yr] | Maximum fraction of MOX fuel |
|---|---|---|---|---|---|
| LWR (1500 $MW_e$) | 25.61 | 1.38 | 23.46 | 0.255 | 16% |
| SMR (150 $MW_e$) | 3.65 | 0.20 | 3.35 | 0.034 | 15% |

Reactors with MOX often use a combination of UOX and MOX, which means that the final consumption of fuel is a combination of Table F.2 and Table F.3. In addition, MOX fuel must take into account the short decay time of Pu-241 (14 years), which means that the fissile content is reduced over time, and that the undesirable Am-241 slowly builds up in unused

MOX fuel. The Uppsala study uses the following mass fractions for their calculations of MOX burnup: (Elter, Zsolt et al., 2020).

Table F.3: (Elter, Zsolt et al., 2020): the fractions of nuclides as used in the UPPSALA database. The fraction of fissile plutonium is 64.1%.

| Plutonium vector (wt%) | | Uranium vector (wt%) | |
|---|---|---|---|
| PU-238 | 2.5 | U-234 | 0.0012 |
| PU-239 | 54.7 | U-235 | 0.2500 |
| PU-240 | 26.1 | U-238 | 99.749 |
| PU-241 | 9.5 | | |
| PU-242 | 7.2 | | |

Appendix G

# Validation of the code used to calculate the nuclear fuel cycle

The code used to calculate the nuclear fuel cycle results has been validated with the RadDecay program, which can solve the Bateman formulas analytically. One of the validations is described below.

It is assumed that an SMR and an LR will run for a single year in 2020, with both producing exactly 1000 kilos of SNF, with composition equal to the fuel from Appendix E (SMR and LR). Of these, the decay of U-232 (t1/2 = 68.9 years, with Pu-236 (t1/2 = 2,858 years) as the main parent nuclide) is calculated over a period of 50 years. This nuclide was chosen because its half-life is in the same order of magnitude as the simulation time, and because it involves ingrowth, which is a test for the correct implementation of the Bateman formulas. After 25 years, the two reactors will be started up again for a single year, again producing 1000 kilos of SNF each. In RadDecay, the activity of U232 is determined under equal conditions. The results are compared in Figure G.1.

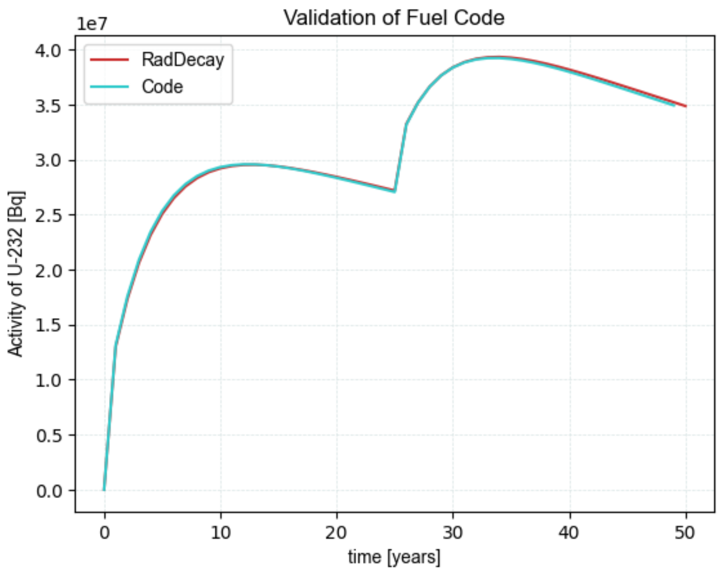


Figure G.1: Comparison of the Bateman analytical formula with the code used. Due to decay of higher actinides, the concentration of U-232 temporarily increases. After 25 years, a second identical amount of SNF is added. The results match almost perfectly.

# Appendix H
# SMR capacity results

Table H.1: HP SMR capacities per region in the ADAPT base case scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0.001 | 0 | 0.001 | 0 | 0.003 | 0.064 | 0.064 | 0 | 0 | 0.064 | 0.068 | 93% |
| 2045 | 0.09 | 0.09 | 0 | 0 | 0 | 0.012 | 0 | 0.01 | 0 | 0.026 | 0.064 | 0.064 | 0 | 0.001 | 0.154 | 0.202 | 76% |
| 2050 | 0.09 | 0.09 | 0 | 0 | 0 | 0.012 | 0 | 0.001 | 0 | 0.026 | 0.616 | 0.616 | 0.111 | 0.111 | 0.817 | 0.855 | 95% |

Table H.2: LP SMR capacities per region in the ADAPT base case scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0.058 | 0.058 | 0 | 0 | 0 | 0.004 | 0 | 0.005 | 0 | 0.022 | 0.141 | 0.141 | 0.153 | 0.153 | 0.352 | 0.382 | 92% |
| 2045 | 0.083 | 0.083 | 0 | 0 | 0 | 0.04 | 0 | 0.045 | 0.237 | 0.237 | 0.141 | 0.141 | 0.153 | 0.153 | 0.613 | 0.698 | 88% |
| 2050 | 0.293 | 0.293 | 0 | 0 | 0 | 0.04 | 0 | 0.045 | 0.237 | 0.237 | 0.377 | 0.377 | 0.253 | 0.253 | 1.16 | 1.245 | 93% |

Table H.3: HP SMR capacities per region in the TRANSFORM base case scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0 | 0 | 0 | 0.001 | 0 | 0.001 | 0 | 0.001 | 0 | 0.003 | 0.313 | 0.064 | 0 | 0 | 0.313 | 0.374 | 84% |
| 2045 | 0.055 | 0.09 | 0 | 0.012 | 0 | 0.012 | 0 | 0.01 | 0 | 0.026 | 0.372 | 0.064 | 0 | 0.001 | 0.427 | 0.55 | 78% |
| 2050 | 0.161 | 0.09 | 0 | 0.012 | 0 | 0.012 | 0 | 0.001 | 0 | 0.026 | 0.414 | 0.616 | 0.053 | 0.111 | 0.628 | 0.707 | 89% |

Table H.4: LP SMR capacities per region in the TRANSFORM base case scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0.052 | 0.052 | 0 | 0 | 0 | 0.003 | 0 | 0.004 | 0 | 0.017 | 0 | 0 | 0 | 0.001 | 0.052 | 0.076 | 68% |
| 2045 | 0.086 | 0.086 | 0 | 0 | 0 | 0.037 | 0 | 0.041 | 0.185 | 0.185 | 0 | 0 | 0 | 0 | 0.272 | 0.35 | 78% |
| 2050 | 0.673 | 0.673 | 0 | 0 | 0 | 0.037 | 0 | 0.041 | 0.185 | 0.185 | 0.26 | 0.26 | 0.094 | 0.094 | 1.212 | 1.29 | 94% |

Table H.5: HP SMR capacities per region in the NoRES-NUC-CAP scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2050 | 0 | 0.016 | 0 | 0 | 0 | 0.001 | 0 | 0.001 | 0 | 0.003 | 0.308 | 0.308 | 0.176 | 0.176 | 0.484 | 0.505 | 96% |

Table H.6: LP SMR capacities per region in the NoRES-NUC-CAP scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2050 | 0.13 | 0.13 | 0 | 0 | 0 | 0.004 | 0 | 0.004 | 0 | 0.017 | 0.246 | 0.246 | 0.115 | 0.115 | 0.491 | 0.516 | 95% |

Table H.7: HP SMR capacities per region in the Nu2xCost scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.11 | 0.11 | 0 | 0.03 | 0.109 | 0.144 | 75% |
| 2045 | 0 | 0.01 | 0 | 0 | 0 | 0.01 | 0 | 0.07 | 0 | 0.03 | 0.22 | 0.22 | 0 | 0.03 | 0.219 | 0.382 | 57% |
| 2050 | 0 | 0.017 | 0 | 0 | 0 | 0.001 | 0.075 | 0.075 | 0 | 0.034 | 0.395 | 0.395 | 0 | 0.038 | 0.47 | 0.56 | 84% |

Table H.8: LP SMR capacities per region in the Nu2xCost scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0.07 | 0.07 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.17 | 0.17 | 0 | 0.05 | 0.232 | 0.306 | 76% |
| 2045 | 0.07 | 0.07 | 0 | 0 | 0 | 0.03 | 0 | 0.04 | 0.17 | 0.17 | 0.17 | 0.17 | 0 | 0.05 | 0.402 | 0.518 | 78% |
| 2050 | 0.137 | 0.137 | 0 | 0 | 0 | 0.032 | 0 | 0.036 | 0.17 | 0.17 | 0.19 | 0.19 | 0.153 | 0.153 | 0.65 | 0.717 | 91% |

Table H.9: HP SMR capacities per region in the TYNDP24 scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0 | 0.01 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.31 | 0.31 | 0 | 0.05 | 0.31 | 0.37 | 83% |
| 2045 | 0.05 | 0.05 | 0 | 0 | 0 | 0.01 | 0 | 0.03 | 0 | 0.03 | 0.36 | 0.36 | 0 | 0.05 | 0.42 | 0.54 | 77% |
| 2050 | 0.05 | 0.05 | 0 | 0 | 0 | 0.01 | 0 | 0.03 | 0 | 0.03 | 0.42 | 0.42 | 0 | 0.05 | 0.47 | 0.6 | 79% |

Table H.10: LP SMR capacities per region in the TYNDP24 scenario with and without the 50MW cut-off. All capacities in GW.

| Year | Limburg | | Mid NL | | North Brabant | | North Holland | | North NL | | South Holland | | Zeeland | | Total | | % of total remaining after 50 MW cut-off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | With | With-out | |
| 2040 | 0.05 | 0.05 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0 | 0 | 0 | 0 | 0.05 | 0.08 | 66% |
| 2045 | 0.09 | 0.09 | 0 | 0 | 0 | 0.04 | 0 | 0.04 | 0.19 | 0.19 | 0 | 0.01 | 0 | 0 | 0.27 | 0.36 | 75% |
| 2050 | 0.54 | 0.54 | 0 | 0 | 0 | 0.04 | 0 | 0.04 | 0.19 | 0.19 | 0.25 | 0.25 | 0.1 | 0.1 | 1.09 | 1.16 | 94% |

Appendix I
# Profitability electricity generation options

The tables below provide the underlying data of the graphs presented in Section 4.2.7 ('Impact on profitability of key technologies'). Note that profits are expressed in 2015 euros. In 2024 euros, costs and prices are approximately 30% higher.

Table I.1: Average capture prices of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the ADAPT and TRANSFORM scenarios (in €/MWh)

| ADAPT | No Nuclear | | Baseline | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | 215 | 289 | 209 | - |
| Nuclear Large | 79 | - | 77 | 60 |
| Wind Onshore | 34 | 46 | 33 | 39 |
| Wind Offshore | 38 | 47 | 37 | 40 |
| Sun PV | 42 | 35 | 42 | 35 |
| TRANSFORM | No Nuclear | | Baseline | |
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | 350 | 239 | 356 | 213 |
| Nuclear Large | 78 | - | 70 | 56 |
| Wind Onshore | 31 | 39 | 29 | 35 |
| Wind Offshore | 35 | 38 | 33 | 35 |
| Sun PV | 41 | 36 | 42 | 35 |

Notes: A '-' indicates that the technology in question is not dispatched in the scenario concerned; The case 'No Nuclear' implies 'no new nuclear capacity investments'. So, any figure for 'Nuclear Large' in the case 'No Nuclear 2040' refers to the existing, installed nuclear plant in Borssele (which lifetime is assumed to be extended up to the early 2040s).

Table I.2: Levelized costs of energy (LCOE) of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the ADAPT and TRANSFORM scenarios (in €/MWh)

| ADAPT | No Nuclear | | Baseline | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | 270 | 215 | 273 | - |
| Nuclear Large | 96 | - | 96 | 83 |
| Wind Onshore | 27 | 23 | 27 | 23 |
| Wind Offshore | 33 | 32 | 32 | 31 |
| Sun PV | 43 | 36 | 43 | 36 |
| TRANSFORM | No Nuclear | | Baseline | |
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | 499 | 326 | 651 | 504 |
| Nuclear Large | 96 | - | 96 | 84 |
| Wind Onshore | 27 | 23 | 27 | 23 |
| Wind Offshore | 33 | 31 | 32 | 30 |
| Sun PV | 43 | 36 | 43 | 36 |

Notes: See Table I.

Table I.3: Average profits per MWh of major generation technologies of the Dutch power system in 2040 and 2050 for both the Baseline and No Nuclear cases of the ADAPT and TRANSFORM scenarios (in €/MWh)

| ADAPT | No Nuclear | | Baseline | |
|---|---|---|---|---|
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | -56 | 74 | -65 | - |
| Nuclear Large | -17 | - | -19 | -23 |
| Wind Onshore | 6 | 23 | 5 | 16 |
| Wind Offshore | 6 | 15 | 5 | 9 |
| Sun PV | -1 | -1 | -1 | -1 |
| TRANSFORM | No Nuclear | | Baseline | |
| | 2040 | 2050 | 2040 | 2050 |
| Gas CCGT | -149 | -88 | -296 | -291 |
| Nuclear Large | -19 | - | -25 | -28 |
| Wind Onshore | 4 | 16 | 2 | 12 |
| Wind Offshore | 3 | 7 | 1 | 5 |
| Sun PV | -1 | 0 | -1 | 0 |

Notes: See Table I.

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