Advances in Applied Energy 1 (2021) 100009

Contents lists available at ScienceDirect

Advances in Applied Energy

journal homepage: www.elsevier.com/locate/adapen

Measuring accuracy and computational capacity trade-offs in an hourly integrated energy system model

Amirhossein Fattahi[a,*], Manuel Sánchez Diéguez[a], Jos Sijm[b], Germán Morales España[b], André Faaij[a,b]

[a] University of Groningen, Netherlands
[b] TNO Energy Transition, Netherlands

ARTICLE INFO

Keywords:
Energy system modeling
Modeling trade-offs
Modeling capabilities
Flexibility
Hourly temporal resolution

ABSTRACT

Improving energy system modeling capabilities can directly affect the quality of applied studies. However, some modeling trade-offs are necessary as the computational capacity and data availability are constrained. In this paper, we demonstrate modeling trade-offs resulting from the modification in the resolution of four modeling capabilities, namely, transitional scope, European electricity interconnection, hourly demand-side flexibility description, and infrastructure representation. We measure the cost of increasing resolution in each capability in terms of computational time and several energy system modeling indicators, notably, system costs, emission prices, and electricity import and export levels. The analyses are performed in a national-level integrated energy system model with a linear programming approach that includes the hourly electricity dispatch with European nodes. We determined that reducing the transitional scope from seven to two periods can reduce the computational time by 75% while underestimating the objective function by only 4.6%. Modelers can assume a single European Union node that dispatches electricity at an aggregated level, which underestimates the objective function by 1% while halving the computational time. Furthermore, the absence of shedding and storage flexibility options can increase the curtailed electricity by 25% and 8%, respectively. Although neglecting flexibility options can drastically decrease the computational time, it can increase the sub-optimality by 31%. We conclude that an increased resolution in modeling flexibility options can significantly improve the results. While reducing the computational time by half, the lack of electricity and gas infrastructure representation can underestimate the objective function by 4% and 6%, respectively.

Introduction

Increasing the share of VRES is one of the pathways to meet long-term decarbonization targets. As the share of VRES increases, the fine temporal resolution and detailed technological representation of ESM can have a substantial impact on analyzing dispatch and flexibility options such as short-term storage, seasonal storage, DSM, VRE curtailment, and cross-border trade. Further electrification of the energy sys-

Abbreviations: ABM, Agent-based Model; BU, Bottom-up; CAES, Compressed Air Energy Storage; CCUS, Carbon Capture, Utilization, and Storage; CCU, CCS, Carbon Capture and Utilization; CCS, Carbon Capture and Storage; CHP, Combined Heat and Power; CTL, Clustered Technological Learning; DAC, Direct Air Capture; DSM, Demand Side Management; ENSYSI, Energy System Simulation; ESM, Energy System Model; ETL, Endogenous Technological Learning; ETS, Emission Trading System; EU, European Union; EV, Electric Vehicle; GHG, Greenhouse Gas; GIS, Geographical Information System; GTS, Gasunie Transport Service; HD pipeline, High-density pipeline; HTR, Hourly Temporal Resolution; HV grid, High Voltage grid; ICE, Internal Combustion Engine; IEM, Integrated energy models; IESA, Integrated Energy System Analysis; IESA-Opt, Integrated Energy System Analysis - Optimization; LD pipeline, Low-density pipeline; LP, Linear Programming; LULUCF, Land Use, Land-use Change, and Forestry; LV grid, Low Voltage grid; MACC, Marginal Abatement Cost Curve; MAF, Mid-term Adequacy Forecast; MD pipeline, Medium Density pipeline; MIP, Mix-integer programming; MRL, Multi-regional Learning; MV grid, Medium Voltage grid; NECP, National Energy and Climate Plan; OESM, Optimization energy system model; OPF, Optimal Power Flow; PBL, The Netherlands Environmental Assessment Agency; PHES, Pumped Hydro Energy Storage; P2Chemicals, Power to Chemicals; P2Gas, Power to Gas; P2Heat, Power to Heat; P2Hydrogen, Power to Hydrogen; P2Liquids, Power to Liquids; P2Mobility, Power to Mobility; SSAS, Solid State Ammonia Synthesis; SSP, Shared Socioeconomic Pathway; TD, Top-down; TES, Thermal Energy Storage; TNO, Netherlands Organization for Applied Scientific Research; TYNDP, Ten-year Network Development Plan; UoC, Units of capacity; VOLL, Value of Lost LlLoad; VRE, Variable Renewable Energy; VRES, Variable Renewable Energy Sources; V2Grid, Vehicle to Grid; wCCS, With Carbon Capture and Storage.

* Corresponding author.
E-mail address: a.fattahi@rug.nl (A. Fattahi).

https://doi.org/10.1016/j.adapen.2021.100009
Received 29 January 2021; Received in revised form 3 February 2021; Accepted 4 February 2021
Available online 8 February 2021
2666-7924/

tem increases the need for analyzing sector coupling technologies such as P2Heat, P2Gas [1], P2Hydrogen [2], P2Chemicals, and P2Mobility [3]. Moreover, centralized or decentralized [4] infrastructural constraints can considerably affect long-term energy system planning [5].

Optimization ESMs have been used extensively in the energy modeling community, focusing either on the planning or operational aspects of the energy system. However, high temporal granularity (e.g., hourly time steps) and operational details (e.g., ramping constraints) are usually neglected in these long-term energy system models [6]. Therefore, they cannot adequately address operational constraints for long-term planning problems; for instance, the effect of flexibility options on energy system investment decisions.

The analysis of flexibility options in the energy system requires enhanced modeling capabilities. However, enhancements can be constrained by several factors, such as data availability and computational capacity. Consequently, based on the focus of the model, modelers have to make various simplifications in parameters such as the temporal resolution, technological details, spatial constraints, and underlying methodology. These simplifications can have a substantial impact on the energy system analysis in terms of feasibility and sub-optimality of results and calculation times. Therefore, a modeling trade-off should be made to maintain the balance between available resources and the required accuracy of the results.

Although several studies have investigated energy system modeling trade-offs, each of them neglects some energy system parameters that can affect the results. For instance, one study shows that increasing the temporal resolution in a power system model with high penetration of intermittent renewables can result in increased power system costs [7]. Similarly, another study shows a substantial reduction in baseload power investment as the temporal resolution increases from coarse time slices to hourly [8]. Another realizes the spatial trade-offs in power system modeling [9]. However, these studies neglect the interdependencies of the power system and other energy sectors. Another study quantifies the impact of improving the temporal resolution and operational details for varying penetration levels of intermittent renewable energy sources (IRES) [10]. However, it disregards the grid and cross-border trade. Another study illustrates the impact of temporal resolution on the share of renewables and CO_2 emissions using three different energy models [11]; however, it neglects the interconnection with neighboring nodes and countries. Other studies show that the absence of operational constraints in an energy system model underestimates wind curtailment and overestimates baseload plants [12]; however, it links a power system model with an energy system model by soft-linking method, neglecting real-time energy system interdependencies.

The novelty of this study lies in the quantification of some modeling trade-offs by employing an applied energy system model that covers the mentioned gaps, namely, covering all energy sectors, including grid infrastructure, and integrating a transnational linear power system representation that includes cross-border trade. We apply a reference scenario of the Netherlands as a case study, while the results can be interpreted for other similar national energy systems.

We use the IESA-Opt model, which is part of the IESA modeling framework [13] and can be used to quantify the value of flexibility in long-term energy system analysis. Among all the modeling capabilities of IESA-Opt, four are discussed in this paper. First, the transitional scope (i.e., multi-period solve) allows the incorporation of multi-period factors such as technological lifetime, decommissioning, technological learning, and efficiency improvements, in energy models. At the expense of a higher computational load, the transitional model enables pathway conclusions to be drawn, such as optimal periods to invest in certain technologies. Second, integrating European electricity dispatch with the national ESM provides cross-border trade flexibility at hourly time-steps. Several national ESMs represented the power generation sector of neighboring countries by including their dispatch decisions (e.g., [14]). In highly interconnected systems (e.g., northwest Europe), neglecting cross-border trade or having a static representation of cross-border flows can lead to inaccurate technology portfolio and system cost estimates [15]. Third, a detailed description of flexibility options at hourly time-steps is necessary for modeling the integration of high shares of VRES [16]. Moreover, modeling all energy system flexibility options such as P2Heat, P2Mobility, P2Liquid, and P2Gas is necessary to accurately estimate energy storage needs [17]. IESA-Opt includes a detailed list of flexibility options (fully described in Table 4) divided into six main groups: flexible CHPs (11 technologies), shedding (6 technologies), demand response (2 technologies), storage (3 technologies), smart charging (3 technologies), and V2Grid (1 technology). Finally, the inclusion of infrastructural constraints allows the system to account for infrastructure development costs. The existing infrastructure is not fully compatible with a low-carbon energy system mainly due to the lack of CCUS and hydrogen networks [18]. All four capabilities can have major effects on the long-term planning of the energy system.

This study aims to measure the cost of increasing resolution in each modeling capability in terms of computational time and energy system modeling indicators, notably, system costs, emission prices, electricity generation, and import and export levels.

With this aim, in Section 2, we provide a brief introduction to the model, followed by the reference scenario description in Section 3. Then, in Section 4, we generate several cases for each of these four capabilities. Section 5 demonstrates the impact of enabling and disabling each of these capabilities on system configuration indicators. Finally, we draw a conclusion on modeling choices for a low-carbon energy system based on project aims and available computational resources.

The model's source code, along with its database and all the results, is accessible through the online portal of the model [19].

Brief introduction to the IESA-Opt model

This open-source national model uses the linear programming (LP) method to simultaneously optimize the short-term hourly operation and long-term 5-year interval planning problems from 2020 to 2050. The model includes multi-period techno-economic data of more than 700 technologies, in which 335 technologies represent all energy sectors of the Netherlands (as well as key cross-sectoral technologies such as P2Heat, P2Gas, P2Hydrogen, P2Liquids, P2Mobility, and V2Grid), and 365 technologies represent the electricity dispatch of EU countries in 20 nodes. The model accounts for emissions from non-energy sources such as enteric fermentation, fertilizers, manure management, and refrigeration fluids, as well as emissions from energy sources divided into national and European ETS, and non-ETS emissions. The energy infrastructure is modeled in ten networks for different pressures of natural gas, hydrogen, CCUS, and heat, and different voltage levels of electricity.

The main goal of IESA-Opt is to quantify the cost-optimal path for an integrated energy system transition towards a highly decarbonized future in which country-specific emission reduction targets are met. In addition, the model must be able to select from a very rich technology pool of options and be able to deal with the operational complexity of VRES. This means that the tool output consists of two main components. First, the optimal planning of the technology stocks that the system requires to satisfy economic activities in the transitional period. Second, the optimal intra-year operation of such a technological stock. This interaction between the short- and long-term decisions at an integrated level for the entire energy system makes it possible to simultaneously provide high temporal and technological granularities, which is the main contribution of the model to the scientific sphere.

IESA-Opt uses the LP approach and saves the computational capacity for increasing temporal and technological details of the energy system. Conventional large-scale long-term planning energy system models frequently use LP methodology to avoid excessive computational loads. Operational energy system models, especially power system models, tend to employ mixed-integer linear programming (MILP) methodology to account for binary or integer variables such as investment and unit-commitment decisions. The choice of LP over MILP methodology can

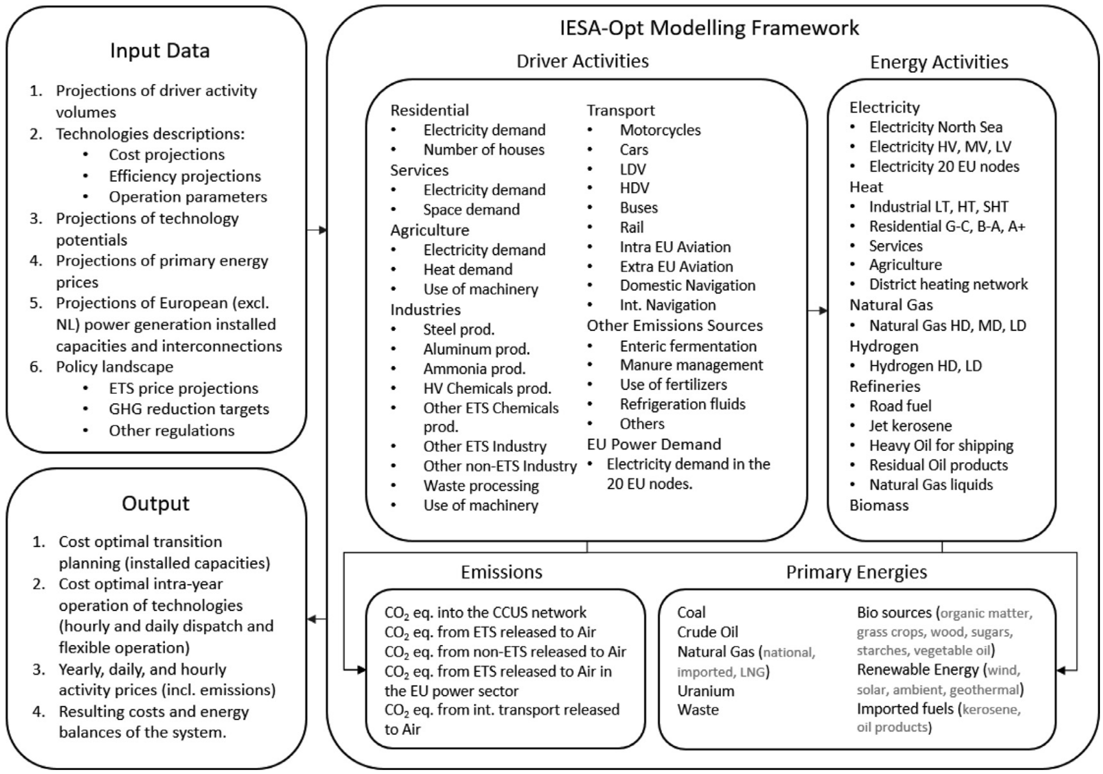

Fig. 1. Conceptual framework of the IESA-Opt model.

considerably reduce the computational time while having a negligible impact on the modeling results, especially in energy systems with high shares of VRES [20]. The computational time of the LP formulation can be significantly lower than that of the MILP approach while providing relatively high precision in modeling relevant flexibility options [21].

The conceptual representation of IESA-Opt is illustrated in Fig. 1. The modeling framework differentiates between driver activities and energy activities. Driver activities indicate the energy demand in the system (e.g., the production of steel or the use of passenger cars), while energy activities correspond to specific forms of energy carriers (e.g., electricity or hydrogen). The model requires the projected volumes of the driver activities as input to endogenously determine the optimal portfolio of technologies to meet the energy demand.

Reference scenario

To facilitate the analysis of the impact of considering detailed European interconnectivity, cross-sectoral flexibility, and infrastructure representation in IESA-Opt, the reference scenario used for this paper focuses on the adoption of a large share of VRES to produce electricity. Here, we present a brief description of the reference scenario, including the Netherlands's energy demand and seasonal and daily power loads of EU nodes in 2050.

Scenario storyline

The projected development and part of the resource costs are extracted from JRC's POTEnCIA central scenario for the Netherlands [22], drawn accordingly with GDP growth rates presented in the 2018 ageing report [23]. Such projections lean towards business-as-usual economic development, which would fall within the narrative of the second shared socioeconomic pathway (SSP2) [24]. The costs of biomass were extracted from the reference storyline of the ENSPRESO database [25], as well as most of the considered potentials for renewable technologies in the Netherlands.

The environmental policy landscape of the Netherlands is presented by the Dutch government in the National Energy and Climate Plan (NECP) [26] and sets targets of 49% and 95% emission reductions for 2030 and 2050, respectively, as compared with 1990 levels. Furthermore, there seem to be no short or mid-term plans to further expand nuclear power and it will most probably disappear from the energy mix after 2033 [27]. In addition, the climate agreement voids the use of coal for power generation after 2030, although it is not yet fully clear if it will be allowed in combination with CCUS. Therefore, coal power plants are not allowed after 2030 in the scenario, while investment in coal with CCUS remains an option.

The technology-specific parameters refer to the activity inflows and outflows of each technology (energy or commodity balance) and the cost levels of the technologies (investment, fixed operational, and variable operational costs). The reference scenario uses data from central scenario descriptions of different sources. Most of the technologies described in IESA-Opt are based on the reference scenario of the ENSYSI model [28], where low-carbon technologies experience a learning rate of at most 20%. Technology data projections of the transport sector are obtained from the POTEnCIA central scenario [22]. In addition, data projections for technologies such as P2Liquid alternatives, electrolyzers, and direct-air-capture units are obtained from TNO's technology factsheets [29]. The complete technology data assumptions, as well as the link to the sources, can be found in the online portal of the model.

As IESA-Opt dispatches electricity for the entire EU, the climate targets of EU member states' power systems can also influence national power system development. Member states must cope with EU targets, but further voluntary contributions might vary, and such a variety of responses might strongly influence the outcome of the model, as the level of discrepancy in national policies might result in price differences and therefore highly imbalanced import and export flows. To cope with this, the reference scenario considers EU generation assets from the MAF 2016, and the sustainable transition scenario runs until 2035 [30], which is then complemented with updated data from the national trends

Table 1
Activity volumes considered in the reference scenario.

Sector	Driver	Units	Values 2020	2030	2040	2050	Source
General	Heat degree days	[HDD]	2900	2800	2700	2600	[32]
Residential	Appliances electricity demand	[PJ]	66.0	68.7	70.6	71.8	[33]
	Number of houses	[Mhouses]	8.2	8.8	9.2	9.6	[33,28]
Services	Appliances electricity demand	[PJ]	138.4	137.6	138.9	143.9	[33]
	Used space	[Mm^2]	513.0	538.7	554.5	559.1	[33]
Agriculture	Appliances electricity demand	[PJ]	29.0	30.2	31.2	32.6	[33]
	Heat demand for horticulture	[PJ]	106.9	111.2	115.4	123.0	[33,28]
	Heat demand for agriculture	[PJ]	8.4	8.7	9.0	9.6	[33,28]
	Machinery consumption	[PJ]	27.1	27.8	28.5	30.2	[33]
Industry	Steel production	[Mton]	6.9	6.7	6.8	7.3	[33]
	Aluminum production	[Mton]	0.2	0.2	0.2	0.2	[33,28]
	Ammonia production	[Mton]	3.2	3.4	3.6	3.8	[34]
	High value chemicals production	[Mton]	8.5	9.4	9.7	10.0	[33,28]
	Other ETS chemical industry	[Index]	1.1	1.3	1.4	1.7	[33,28]
	Other ETS industry	[Index]	1.0	1.1	1.1	1.2	[33,28]
	Other non-ETS industry	[Index]	1.0	1.0	1.0	1.0	[33,28]
	Machinery consumption	[PJ]	24.5	27.4	28.6	29.4	[33]
Waste	Waste incineration	[Mton]	7.6	9.1	10.6	12.3	[33,28]
	Waste sewage	[PJ]	3.7	4.3	4.9	5.6	[28]
	Waste landfill	[PJ]	0.4	0.0	0.0	0.0	[28]
Transport	Motorcycles	[Gvkm]	5.1	5.8	6.5	7.2	[33]
	Passenger cars	[Gvkm]	103.4	107.0	111.7	117.4	[33]
	Light-duty vehicles	[Gvkm]	21.2	24.3	27.4	32.3	[33]
	Heavy-duty vehicles	[Gvkm]	7.0	7.4	7.8	8.8	[33]
	Buses	[Mvkm]	617.2	606.0	616.1	650.6	[33]
	Rail	[Mvkm]	168.7	195.2	221.1	231.9	[33]
	Intra-EU aviation	[Mvkm]	211.5	264.2	344.5	432.2	[33]
	Extra-EU aviation	[Mvkm]	668.5	740.5	794.0	848.2	[33]
	Inland-domestic navigation	[Mvkm]	54.6	70.1	81.0	92.8	[33]
	International navigation	[Mvkm]	112.9	124.7	135.3	146.3	[33]
Power EU	EU electricity demand	[EJ]	11.7	11.8	12.0	11.9	[30]

TYNDP scenario 2020 for the year 2040 [31]. Based on this configuration, we then run a highly decarbonized capacity expansion plan for all of Europe for the years 2040, 2045, and 2050 to ensure that the EU's assets are aligned with the Netherlands' assets. In this way, we avoid highly unbalanced electricity import and export situations due to modeling discrepancies.

Energy demand in the Netherlands

The energy demand in IESA-Opt is derived from certain economic drivers, which require an energy supply. The model considers national economic activities for the residential, services, agricultural, industrial, and transport sectors, as shown in Table 1 These activities are endogenously translated to energy requirements by the model, based on the choice of technology. For instance, there is an exogenous requirement to produce 7.3 Mton of steel in 2050. This amount of steel can be produced using several technologies such as blast furnaces, blast furnaces with CCS, Hisarna, Hisarna with CCS, and Ulcowin. Each of these technologies has a different energy balance. The model optimally decides which technology is the best to be used, considering several parameters such as its costs, efficiency, and emissions.

In addition to national economic activities, the model requires the expected demand for electricity in European countries as an input. The model requires electricity demand data on the following European countries: United Kingdom, Norway, Denmark, Germany, Belgium, Ireland, Sweden, France, Switzerland, Austria, Poland, Czech Republic, Slovakia, Spain, Portugal, Italy, and Finland, as well as aggregated figures on Baltic countries, Balkan countries within the EU, and Balkan countries outside the EU.

Assumed fuels and resources costs

The model satisfies the need for energy demands by the combination of primary energy supply, conversion of primary energy in final energy and final energy imports. Therefore, the costs assumed for the primary assets supplied to the system are direct input to the model and key part of the scenario definition. These primary assets can be distinguished as conventional fuels, biomass sources, and the ETS allowances projected costs. The data for the reference scenario used in this paper is composed of the following sources and presented in Table 2. First, conventional fuels prices projections are retrieved from POTEnCIA's Central Scenario database [33]. Then, the price projections of the bio-resources are based on ENSPRESO-BIOMASS reference scenario [25]. Finally, the ETS allowance cost projections are retrieved from two sources, the 2019 Netherland's Climate Energy Outlook [34] for the 2020–2030 period, and the CPB high-efficiency scenario projections [35] for the period 2030–2050.

Transition potentials

The potential assumed for technologies to develop has a large influence on the definition of the scenario. These potentials determine the maximum allowed installed capacity of each technology in the transitional period. Many of these assumed potentials have an important influence in the determination of transitionary costs, notably potentials for renewable energy sources (including biomass), and for storage of carbon dioxide. The reference scenario bases the storylines of these potentials accordingly with the ENSPRESO reference scenario for biomass [25] and the TNO's OPERA model reference scenario. Table 3 shows assumed potentials for the reference scenario.

Daily and seasonal power load curves

The electricity demand is an endogenous parameter in IESA-Opt, giving the model the ability to decide the optimal level of electrification. However, the model distributes the demand based on an exogenous normalized load profile. The total national load profile is endogenously calculated in the post-processing as the sum of the hourly profile of all elec-

Table 2
Fuel and resource cost assumptions for the whole transitional period considered in the reference scenario.

Commodity	Units	Values 2020	2030	2040	2050	Source
Coal	[€$_{2019}$/GJ]	3.0	3.7	4.1	4.4	[33]
Oil	[€$_{2019}$/GJ]	11.6	17.0	18.8	19.6	[33]
Natural Gas	[€$_{2019}$/GJ]	6.5	9.3	10.3	10.7	[33]
Uranium	[€$_{2019}$/GJ]	0.8	0.8	0.8	0.8	[34]
Waste	[€$_{2019}$/GJ]	6.9	7.0	7.0	7.0	[36]
Manure	[€$_{2019}$/GJ]	0.1	0.1	0.1	0.0	[36]
Dry Organic Matter	[€$_{2019}$/GJ]	4.5	4.2	4.1	4.0	[36]
Grass Crops	[€$_{2019}$/GJ]	9.5	8.7	8.4	8.2	[36]
Wood (crops, and others)	[€$_{2019}$/GJ]	8.2	7.4	6.9	6.4	[36]
Sugars	[€$_{2019}$/GJ]	4.3	4.6	4.6	4.6	[36]
Starch	[€$_{2019}$/GJ]	15.9	21.3	21.5	21.9	[36]
Vegetable Oil	[€$_{2019}$/GJ]	26.5	38.1	38.0	38.0	[36]
ETS Allowance	[€$_{2019}$/tonCO_2]	22	47	105	160	[34,35]

Table 3
Key technological potentials assumed for the whole transition period in the reference scenario.

Potential	Units	Values 2020	2030	2040	2050	Source
Nuclear power	[GW]	0.48	0.48	0	0	{TNO}
Offshore wind	[GW]	3	15	55	97	{TNO}
Onshore wind	[GW]	5.5	8	8	8	{TNO}
Solar PV fields	[GW]	1	3	9	15	{TNO}
Industrial Solar PV	[GW]	1.5	9	17	25	{TNO}
Residential Solar PV	[GW]	3	12	21	30	{TNO}
Geothermal Energy	[PJ/y]	10	50	125	200	[36]
Waste	[PJ/y]	42.4	50.6	58.9	68.5	[36]
Wet organic matter	[PJ/y]	4.3	4.9	5.7	6.5	[36]
Manure	[PJ/y]	48.7	48.9	48.9	48.9	[36]
Dry organic matter	[PJ/y]	5.3	5.3	5.7	6.2	[36]
Grass Crops	[PJ/y]	11.7	21.9	19.6	17.1	[36]
Wood	[PJ/y]	15.0	16.1	18.7	19.8	[36]
Sugars	[PJ/y]	14.2	20.9	17.6	14.4	[36]
Starch	[PJ/y]	0.7	0.8	0.9	1.0	[36]
Vegetable Oil	[PJ/y]	14.2	21.1	17.6	14.4	[36]
Storage of CO_2	[MtonCO_2/y]	17	25	25	25	{internal}

tricity consumer technologies in the system. Therefore, the load profile can vary from scenario to scenario. These demand profiles are briefly described as follows.

In IESA-Opt, the normalized electricity load profile of each country can vary at each hour of the year. These profiles are exogenous to the model and we assume they remain the same for all periods up to 2050. Fig. 2 demonstrates the yearly normalized (i.e., the sum of all hourly loads in a year is equal to one) electricity load profile for all EU nodes in the IESA-Opt model. Southern countries such as Italy and Spain are assumed to have higher loads in summer, mainly due to the need for electrified cooling. We assume northern countries such as Great Britain, Norway, Sweden, and Finland to have strong seasonal variability, while other countries have a milder load profile during the year.

The daily load profile can vary depending on the season and day of the week. Fig. 3 shows the daily load profile of two random Thursdays and two random Sundays in winter and summer. In general, summer days have a lighter load compared to winter days. Moreover, the load can have a second peak in winter days owing to the need for extra heating and lighting.

Method: case descriptions

To explore the modeling trade-offs, we designed a set of cases in which we progressively enable specific capabilities applied to the reference scenario presented in Reference Scenario Section 3. The families of cases were named: A, for the cases in which we explore the granularity of the scope of the transition; B for cases exploring different representations of the EU power system; C, for cases exploring the enabling of diverse demand-side flexibility archetypes in the model; and D, for cases exploring the different levels of infrastructure representation.

The cases were generated to analyze the granularity level of the system configuration indicators. Therefore, the focus of this study is on relative results rather than absolute terms. Moreover, some cases represent hypothetical scenarios rather than practical scenarios.

A cases: transitional scope

To explore modeling capability, the reference scenario was run in IESA-Opt under four different cases that consider different transitional scopes. Each case varied the years considered for the transition. The first case (A1) determined the cost-optimal configuration for 2050; the second case (A2) did the same but for the years 2030 and 2050 simultaneously, where the remaining stocks from previous investments are still reflected in 2050; similarly, the third case (A3) did the same but for the years 2020, 2030, 2040, and 2050; and finally, the last case (A4) corresponded to the full deployment of the IESA-Opt capabilities, which covers the years between 2020 and 2050 at intervals of 5 years (7 periods in total). Case A3 was used as the reference case (R-A3) for family B and C cases, as it provided good results as an objective comparative framework and it required significantly less time than case A4. This means that all the following groups of cases (B, C, and D) consider the years 2020, 2030, 2040, and 2050 as the transitional scope.

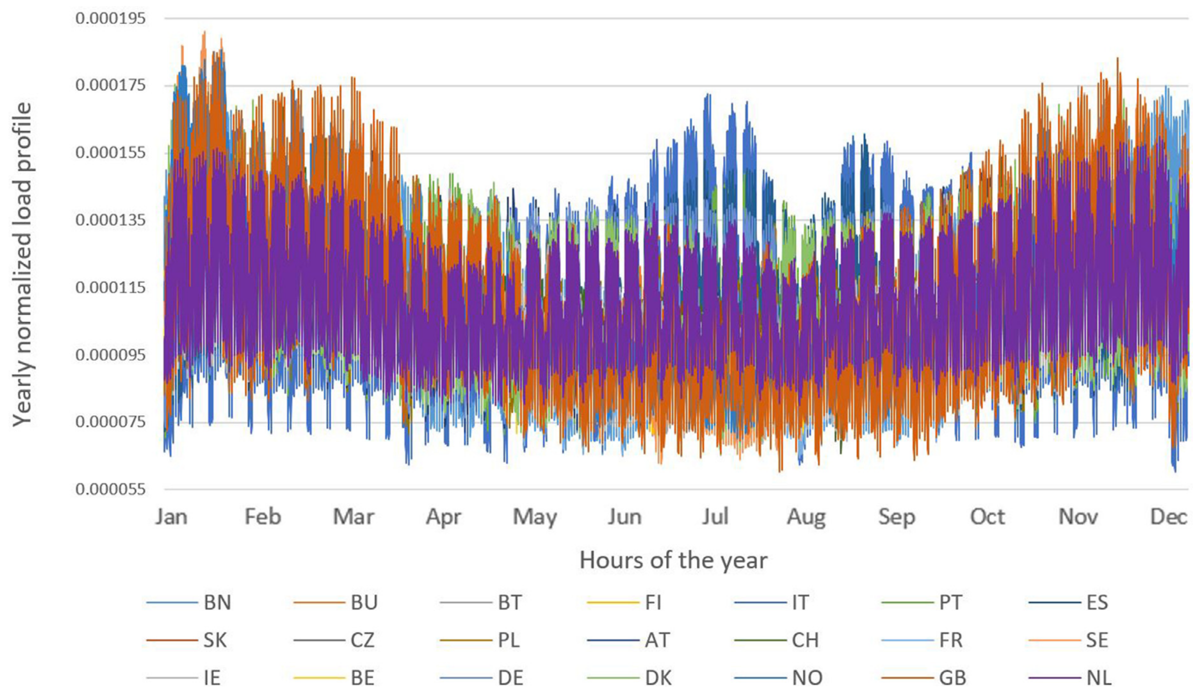

Fig. 2. EU countries' yearly electricity load profiles. IESA-Opt assumes a high seasonal variability of load profile for northern countries. In addition, a weekly variation can be observed for all countries.

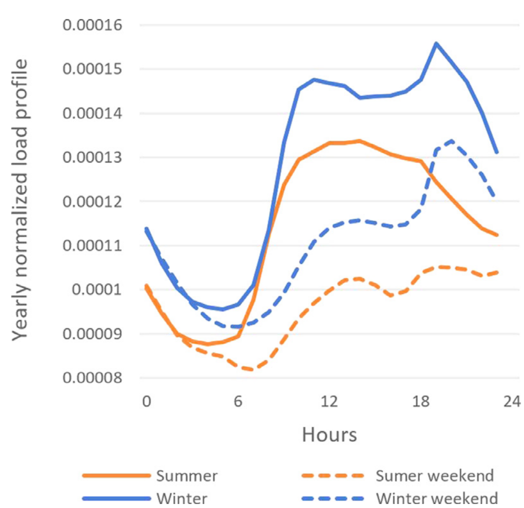

Fig. 3. Electricity load profile of the Netherlands on a random weekday and weekend in summer and winter. Weekday loads have a relatively higher degree of daily variation compared to weekend loads.

B cases: European interconnection

The impact of including European interconnectivity as a modeling capability was explored by progressively increasing the resolution of the interconnected European power system in five different cases. In the first case, B1, the national energy system was isolated as no European power system was represented in the case. In the second case, B2, the national energy system was connected to the European node, which had an average hourly electricity price (extracted from the reference scenario). The third case, B3, considered that all the demand and generation of EU regions were aggregated in one node that could trade electricity with the Netherlands. The next case, B4, provided a more detailed description of the EU power system by considering five interconnected regions (i.e., Belgium, Denmark, Germany, Great Britain, and Norway) as independent nodes. In the last case, R-A3, the resolution was increased to include 21 interconnected European nodes, as demonstrated in Fig. 4.

C cases: demand-side flexibility enhancements

Demand-side flexibility in IESA-Opt was divided into seven major groups: flexible CHPs, shedding technologies, demand response, storage technologies, smart charging of electric vehicles, and vehicle-to-grid storage. Table 4 presents the list of technologies that were considered under each archetype for this paper. To explore the impact of flexibility enhancements in the model, nine different cases were used: one where no flexibility was allowed to occur in model (C1), one that applied the full flexibility description of IESA-Opt (R-A3), and seven intermediate cases in which all forms of flexibility were allowed except for one: without flexible CHPs (C2), shedding technologies (C3), demand response (C4), storage technologies (C5), EV smart charging (C6), and vehicle-to-grid (C7). It is important to mention that further descriptions are still possible; for instance, more industrial activities could apply shedding, some other industrial activities could apply demand response to reschedule their production lines, residential demand response can be disaggregated in specific technologies, and more storage technologies could be analyzed. However, data availability is limited in this topic and the main objective was to test the capabilities of the different archetypes.

D cases: infrastructure representation

IESA-Opt represents the infrastructure of certain commodity networks such as electricity, natural gas, hydrogen, district heating, and captured CO_2 (CCUS). The infrastructure representation imposed timeframe and distance constraints with certain costs in the form of transport lines (such as pipes and cables), transformers, and compressors to adjust to the required operational level of voltage or pressure of the lines. To measure the relevance of including such representations into the energy model, eight cases were designed in which the infrastructure capabilities of IESA-Opt were disabled. The first case disabled infrastructure representations of cables, pipelines, transformers, and compressors of elec-

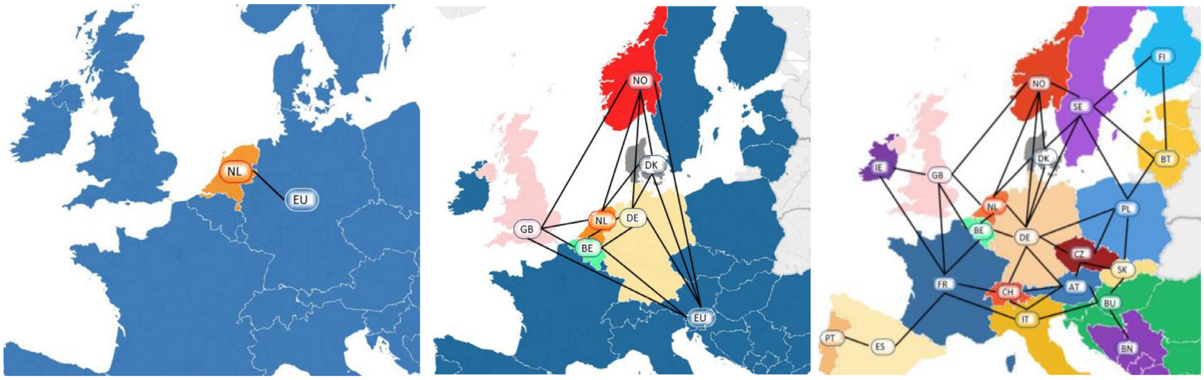

Fig. 4. European interconnection representation in IESA-Opt; from left to right: Cases B3, B4, and R-A3.

Table 4
Flexible technologies considered within each flexibility archetype.

Archetype	Sector	Technology
Flexible CHPs	Waste	CHP from waste
		CHP from waste with CCUS
	Services	Mini CHP from gas
		CHP from gas
		CHP from hydrogen
	Industry	CHP from gas
		CHP from gas with CCUS
		CHP from solid biomass
		CHP from solid biomass with CCUS
		CHP from liquid biomass
		CHP from liquid biomass with CCUS
Shedding	Ammonia	Solid state ammonia synthesis
	Hydrogen	Alkaline electrolyzer
	Refineries	Methanol from electrolysis and DAC
		Methanol from electrolysis and external CO2
		Fischer Tropsch from electrolysis and DAC
		Fischer Tropsch from electrolysis and external CO2
Demand Response	Residential	Flexible residential demand
		Electric heat pumps with water storage tanks
Storage	Power	Compressed air aboveground storage
		Compressed air underground storage
	Heat Network	Hot water storage tank
Smart Charging	Cars	Electric vehicle with SC
	LDVs	Electric vehicle with SC
	HDVs	Electric vehicle with SC
Vehicle-to-grid	Cars	Electric vehicle with V2G

tricity, gas, hydrogen, heat, and CCUS (D1). The second case disabled only the representation of transmission cables and voltage transformers for the transport of electricity (D2). The third and fourth cases ignored pipelines and compressors for the transport of natural gas (D3) and hydrogen (D4), respectively. The fifth and sixth cases ignored the presence of pipelines for district heating (D5) and CCUS (D6), respectively, as only one form of transport is used for their descriptions. Finally, the last case corresponded to the reference case in which all the infrastructure capabilities were enabled in the model (R-A3).

The resulting 25 cases used to explore the level of detail used to describe the four aforementioned modeling capabilities are summarized in Table 5. Different IEMs have different objectives and it is quite common for certain features to be sacrificed for more focus in other areas owing to the limited availability of computational resources. The intent behind testing the four capabilities in a range between the lack of their representation to the most detailed representation available in IESA-Opt was to determine if it was relevant to invest modeling resources to describe them. This could provide valuable guidance for modelers when deciding which capabilities could be sacrificed for the sake of their own modeling goals.

Results

In this section, first, we present an overview of the energy system under the reference case and then demonstrate the changes in modeling capabilities in the coming sub-sectors.

Brief system view under the reference case (i.e. A3-R)

The focus of the paper is on measuring modelling trade-offs; therefore, only a few energy-related results are presented here. The aim is to provide a holistic view of the energy system under the reference scenario. The presented figures can be accessed with higher quality through the model's interactive online user interface [19].

Final energy

The model requires to satisfy energy requirements of system activities, which are described in Table 1 in Reference scenario Section 3. The model optimally provides the required energy for each activity based on techno-economic constraints. As a result, the final energy consumed by each sector in 2050 can be tracked in Fig. 5. The Industry sector accounts for more than half of the final energy in the Netherlands. Almost half of

Table 5
The summary of cases used to explore modeling capabilities. Note that all cases are compared to the R (reference) case, which is the same as A3.

Transitional Scope	European Interconnection	Flexibility Enhancements	Infrastructure Representation
A1: - Cost-optimal configuration of year 2050. **A2:** - Simultaneous cost-optimal configuration of years 2030 and 2050. **A3:** - Simultaneous cost-optimal configuration of years 2020, 2030, 2040, and 2050. **A4:** - Simultaneous cost-optimal configuration of years 2020, 2025, 2030, 2035, 2040, 2045, and 2050.	**B1:** - No European interconnection at all. **B2:** - Simplified-single European interconnection with average EU electricity price. **B3:** - Single interconnection with a European node assuming copper plate among all surrounding countries. **B4:** - Connection with 5 interconnected countries surrounded by one large European node. **R-A3:** - Complete IESA-Opt EU power system representation with 20 surrounding nodes.	**C1:** - Without flexibility. **C2:** - Without CHP's flexibility. **C3:** - Without shedding of conversion technologies. **C4:** - Without demand response. **C5:** - Without storage technologies. **C6:** - Without EV's flexibility. **C7:** - Without vehicle-to-grid flexibility. **R-A3:** - All the flexibility forms considered in IESA-Opt.	**D1:** - Without any representation of infrastructure. **D2:** - Without electricity networks description. **D3:** - Without gas networks description. **D4:** - Without hydrogen networks description. **D5:** - Without CCUS networks description. **D6:** - Without district heating networks description. **R-A3:** - All the infrastructure represented in IESA-Opt.

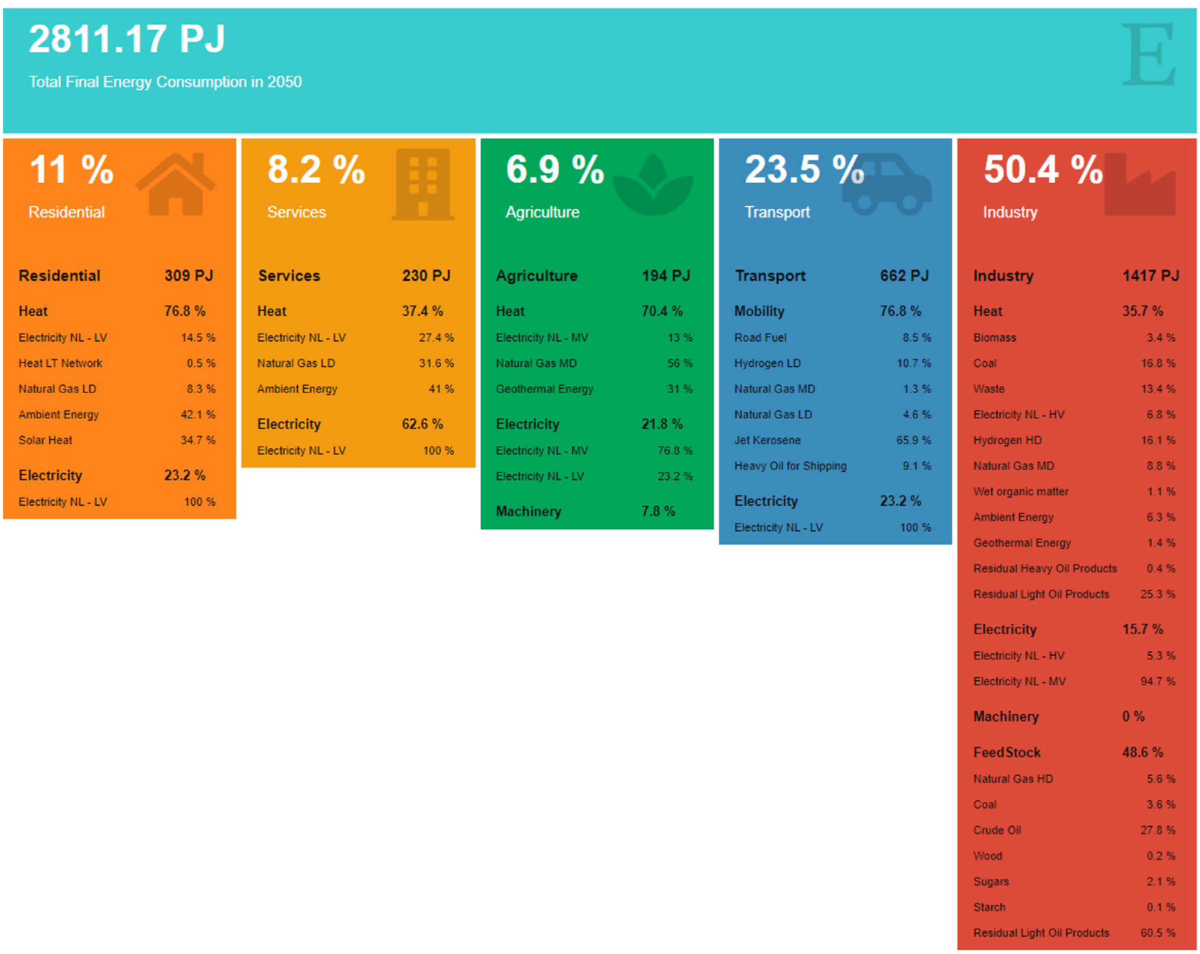

Fig. 5. Final energy consumption by sector and energy carrier in 2050. The industrial sector comprises around half of the Netherland's energy consumption.

the energy consumption in Industry is dedicated to feedstock which is used in refineries to satisfy export demands. In the Transport sector, although the model electrifies the whole passenger car fleet, international aviation and navigation transport rely heavily on fossil fuels. The heat demand in the Agriculture and Residential sectors is met with renewable sources such as electricity, ambient heat, and solar heat.

Activities

The final energy allocation can be represented by sectoral activities as in Fig. 6. The main energy consumption in industry is coming from processing high-value chemicals. More than half of the final energy in the Transport sector is consumed by aviation activities, while international navigation stands for only 10%. Not all activities are visible here; hence, readers are invited to see the interactive graphs on the online user-interface of the model.

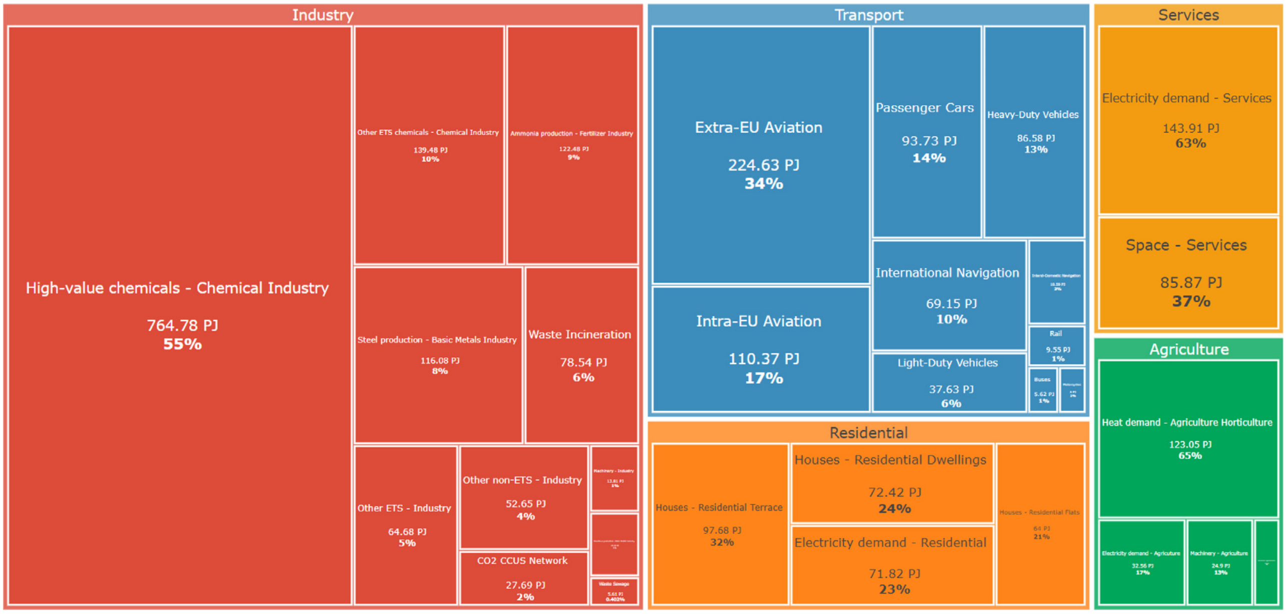

Fig. 6. Final energy consumption by each sector and activity in 2050. Note the considerable share of high-value chemical industry in the final energy consumption.

Fig. 7. Primary energy mix of the Dutch energy system in 2050.

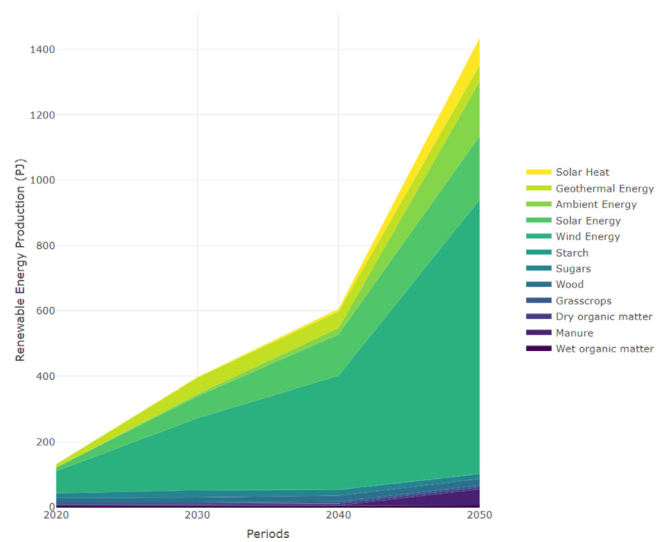

Fig. 8. Renewable energy production transition by source. Wind energy dominates in all periods.

Primary energy mix

Despite the 95% emission reduction policy in the Netherlands by 2050, the primary energy mix in Fig. 7 shows a considerable amount of fossil fuels. A considerable amount of these fossil fuels are used to produce exported chemical products, which are assumed to be at the same levesl of fossil exports for 2050 as of 2020. Moreover, fossil fuels are required to satisfy aviation and navigation activities. The rest of fossil fuels are being used as an industrial feedstock.

Renewable energy production

Renewable energy is mainly produced by wind farms, notably offshore wind in the North Sea region. Besides, as it is demonstrated in Fig. 8, solar energy capacity increases considerably. However, due to the lack of space in the Netherlands, solar energy production growth stops after 2040. After 2040, the solar thermal technology option starts to grow, as it can use the rooftops of residential buildings. Also, the ambient energy grows considerably that refers to the higher installation of heat pumps.

Sankey

A major added value of an integrated energy system model is the capability to analyze the inter-sectoral effects. The Sankey diagram in Fig. 9 demonstrates the energy flows in 2050. The electricity is mainly produced by Wind, Solar, Import from EU, Natural Gas, and Biomass. The electricity can be used to produce Hydrogen (e.g. electrolysis), Natural Gas (i.e. P2Gas), Liquids (i.e. P2Liquids), and Heat (i.e. P2Heat). Chemical liquids play a major role in the energy system of the Netherlands. These liquids are either Imported (by the reference scenario assumption) or produced by (mostly) electricity.

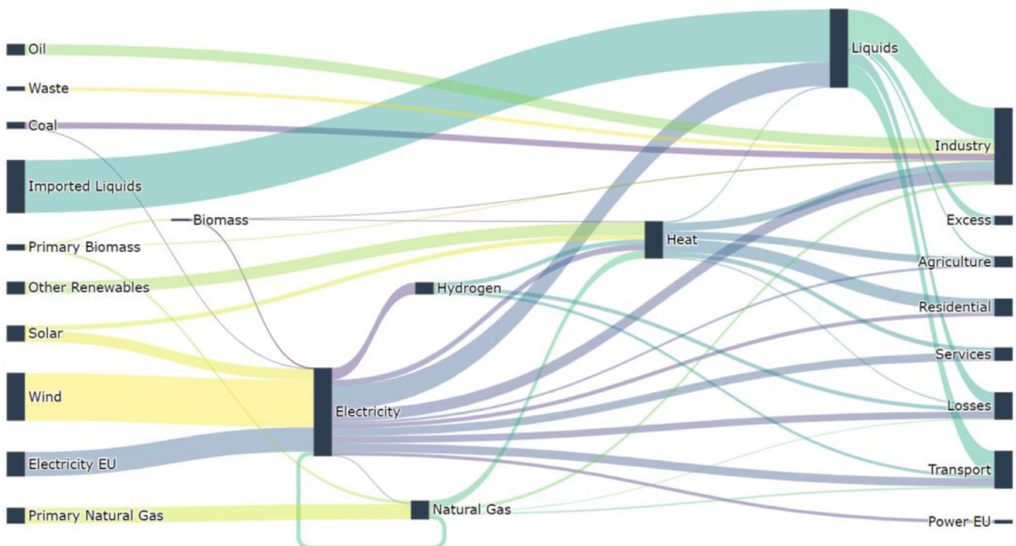

Fig. 9. Energy flow Sankey diagram in 2050. Note the high degree of cross-sectoral interdependencies in the energy system.

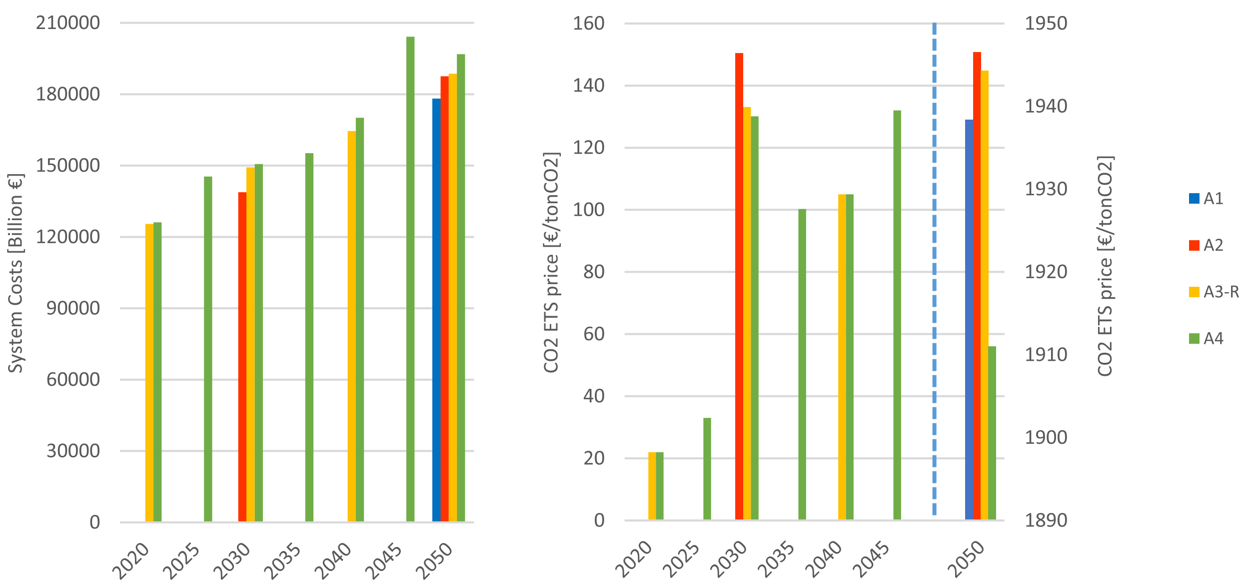

Fig. 10. Left: comparison of the system costs at the different years of the transition for the 4 cases used to explore the transitional scope considerations of the model. Right: comparison of CO2 ETS price between cases A1-A4. To better demonstrate differences in 2050, the results are reflected on the secondary right axis.

Transitional scope

The impact of the number of periods considered for the transition, according to cases A1, A2, A3, and A4, as introduced in 4.1 is illustrated in Fig. 10. It is possible to observe that the number of considered periods strongly impacts the outcome of the system configuration. For instance, the system cost in 2050 increases by 9.5% as the considered transitional periods increase from 1 to 7 periods (A1 vs. A4). This is an expected result, as increasing the number of periods imposes an extra constraint to the problem which is derived from an intrinsic "inheritance" of the existing technological stock from previous years. The difference between 4 and 7 periods (i.e., cases A3 vs. A4) progressively increases with time until it reaches 4.2% for 2050. Furthermore, although less noticeable, the transitional scope also affects the 2050 shadow price of CO_2, as shown in Fig. 10. The CO_2 price of cases A1 to A3 ranged between 1938 and 1956 €/ton of CO_2, while the price in A4 remained at in 1911 €/ton with a maximum difference of 2%. The shadow price for A4 was lower as it already presented a more expensive energy system, thus, if the targets are reduced by 1 ton of CO_2, the system has more "cheaper" options available in comparison to other cases.

The CO_2 price was extracted as the shadow price of the emission constraint, which is the marginal value of the objective function by emitting one extra unit of emissions (i.e., ton) in a certain year. Therefore, this parameter does not necessarily represent the price of CO_2 but rather the costs of marginal technologies to reduce CO_2 emissions. With stricter emissions targets, the shadow price increases further.

To explain the differences in costs, we looked at the sectoral cost composition of the four cases, as presented in Table 6. However, before explaining the differences, it is important to bear in mind that certain technologies become cheaper due to technological learning. For instance, A4 needs to meet system requirements in previous years; therefore, sometimes the investment costs in previous years are more expensive than in 2050. As such, it does not necessarily mean that different costs represent substantially different system configurations but represent a reflection of the technology costs of the periods in which the investments were made. However, few conclusions can be extracted be-

Table 6
Sectoral decomposition of system costs' change for the four transition cases.

Sector	System Costs' change relative to A4 [%] A1	A2	A3	A4 [B€]
Residential	−26.0	2.0	−4.4	22.2
Services	−45.0	−35.6	−32.3	13.9
Agriculture	−7.9	−7.9	0.4	2.5
Industry	−8.2	18.6	3.2	10.6
Transport	−6.6	−6.6	−3.6	75.6
Power NL	3.7	−0.3	−1.6	42.3
Refineries	−31.1	−18.8	−19.4	2.0
Heat Network	−93.3	−74.7	−70.7	0.1
Final Gas	−34.1	−32.3	8.0	3.6
Hydrogen	−17.3	−24.2	−8.9	0.7
Fossil	0.5	3.0	3.9	17.8
Others	−17.6	−15.4	−13.9	1.8

Table 8
Electricity generation in PJ across cases A1 to A4. The overall generation mix does not change considerably.

Electricity mix in 2050 [PJ]	A1	A2	A3	A4
Co-fired Coal wCCS	1.4	1.4	1.4	1.3
CCGT	21.7	21.7	21.6	21.3
CCGT wCCS	15.4	15.4	15.3	15.3
GT	2.8	2.8	2.7	2.6
Biomass	5.6	5.5	5.1	5.3
Onshore Wind	57	56.8	56.8	57.2
Offshore Wind	766.9	767.8	766.5	762.3
Solar PV Fields	41	40.7	40.8	41.3
Industrial Solar PV	70	70	70	70
Residential Solar PV	84	84	84	84
Hydro	0.9	0.9	0.9	1
Imports	418.2	417.9	421.5	374.6
Exports	56.1	56.9	58.5	59.5

fore considering sectoral configurations. For instance, it is evident that having more periods favors the adoption of district heating networks, as well as the role of hydrogen as an energy carrier.

When we focused on configurational aspects, we found that although many of the technological configurations remain practically unchanged, there were notable differences as reported in Table 7. Most of the differences occurred in the transport sector and in the selection of heat technologies. For instance, in case A1, the model opted to use fuel motorcycles vs a predominant mix of electric motorcycles in A4; A1 adopted a 90/10 ratio of smart charging/vehicle-to-grid enhancements for passenger vehicles, while A4 opted for a 60/40 ratio; the ratio of electric to hydrogen buses is 1/3 in A1 versus 7/11 in A4; and A1 used only ICE ships, while A4 distributed the fleet almost evenly between ships using bunker, ICE, and CNG ships. In the residential sector, A4 substituted a tenth of the electric heat pumps with district heating as compared to A1; in the services sector, A1 adopted hybrid heat pumps while A4 went for the full electric heat pumps. In the industrial sector, the ratio of hybrid gas boilers with CCUS and hydrogen boilers was 2/9 and 4/9 for cases A1 and A4 to produce high-temperature heat, respectively. In the same sector, albeit for low-temperature heat, A1 opted for heat pumps while A4 selected geothermal heat. As a consequence, case A4 used 7.3% more electrolyzers to satisfy the hydrogen demand than A1. Finally, 11 Mton of CO_2 of the total emissions were allocated differently as well, where the ETS sectors further reduced their efforts by 2 Mton of CO_2 in A1 than in A4 to allow for more emissions in non-ETS sectors.

The electricity load will increase by almost three times from 340 PJ in 2020 to 1326 PJ in 2050, mainly due to the increase in the electrification rate. The main source to satisfy this substantial demand for the Netherlands will be the installed capacities of offshore wind turbines. In 2050, the electricity generation mix does not change considerably by changing the transitional scope (Table 8). Electricity from solar PV remains an attractive option for the model due to technological learning and cost reductions until 2050. Moreover, the model nearly reaches the 90 GW installed wind offshore capacity, resulting in more than 760 PJ of electricity generated from mainly the North Sea region. The only major change is the reduction in imports in case A4, which can be explained by the reduction in the electricity load due to more accurate modeling assumptions (i.e., modeling the whole transition period).

We provide an overview of selected modeling elements to analyze the effect of the transitional capability in IESA-Opt in Table 9. From this, we can conclude that depending on the goals of the study, fewer transitional periods can be included to save computational time and resources at the expense of providing cost underestimations. The system configuration obtained by the simplified approaches differs only on a few activities and can predict CO_2 prices and system costs with underestimations of 10% or lower. However, it is important to mention that the underestimations provided by the simplifications are not only due to lifetime infeasibilities but also due to the higher effect that technological learning has on the solution when fewer periods are considered.

On the other hand, when discussing the requirements of including a more accurate representation of the transition in IESA-Opt, we can

Table 7
Most significant differences in the use of technologies between cases A1 and A4.

Activity	Technology	Units	A1	A4
Motorcycles	ICE Vehicle - Motorcycle	Gvkm	7.2	1.0
	Electric Battery Vehicle - Motorcycle	Gvkm	0.0	6.3
Passenger cars	Electric Battery Vehicle FLEX - Cars	Gvkm	36.0	24.1
	Electric Battery Vehicle P2G - Cars	Gvkm	3.7	15.4
Buses	Electric Battery Vehicle - Bus	Mvkm	162.6	254.0
	Hydrogen Fuel Cell Vehicle - Bus	Mvkm	488.0	396.6
International navigation	Heavy Oil Ship - International	Mvkm	0.0	58.1
	ICE Ship - International	Mvkm	146.3	38.8
	CNG Ship - International	Mvkm	0.0	49.5
Residential heating	District Heating - LT Heat for Houses A+	PJ	0.3	3.5
	Electric Heat Pump GW - LT Heat for Houses A+	PJ	33.8	30.5
Services heat	Hybrid Heat Pump - LT Heat for Services	PJ	85.9	0.0
	Electric Heat Pump Soil - LT Heat for Services	PJ	0.0	85.8
Industrial HT heat	Hybrid Boiler Gas with CCUS - HT Heat for Industry	PJ	60.6	47.2
	Boiler H2 - HT Heat for Industry	PJ	14.3	28.4
Industrial LT heat	Heat Pump Electricity - LT Heat for Industry	PJ	51.9	0.0
	Geothermal HP - LT Heat for Industry	PJ	0.0	46.8
Hydrogen	Alkaline Electrolyzer - Hydrogen Production	PJ	198.7	214.3
Emissions	ETS sectors	$MtonCO_2$	−18.3	−16.3
	non-ETS sectors	$MtonCO_2$	29.3	27.3

Table 9
Overview of selected modeling elements around the transitional capability in IESA-Opt.

Case	Objective function	Memory needs	Run time	Data requirements	Model description
A1	Infeasibility: 9.2%	13 GB	31 min	Cost and efficiency parameters of technologies for the target year only.	The transition formulation can be avoided.
A2	Infeasibility: 4.6%	28 GB	115 min	Cost and efficiency parameters for all the periods. The initial existing stock becomes more important as more periods are considered.	The transition formulation is required.
A3-R	Infeasibility: 3.7%	54 GB	271 min		
A4	–	89 GB	456 min		

Underestimation of 2050 costs as compared with the case with the best representation available (A4).

Table 10
Sectoral decomposition of the change in system costs for the five EU interconnection cases.

Sector	System Costs' change relative to R [%]				
	B1	B2	B3	B4	R [B€]
Residential	−3.1	−2.8	−0.2	−0.1	21.2
Services	84.2	84.8	0.1	0.6	9.4
Agriculture	0.0	−6.4	1.5	−0.3	2.5
Industry	−0.3	−1.1	−0.1	0.0	10.9
Transport	0.5	0.2	−0.4	−0.4	72.9
Power NL	175.9	4.5	−1.9	−2.6	41.6
Refineries	−22.1	−26.6	−1.2	3.0	1.6
Heat Network	−31.8	−50.0	4.5	0.0	0.0
Final Gas	−12.5	−14.5	0.1	0.2	3.9
Hydrogen	−6.7	−9.1	−12.3	−17.8	0.6
Fossil	−4.1	−5.3	−0.2	−0.1	18.5
Others	41.6	30.0	−2.1	−1.7	1.5

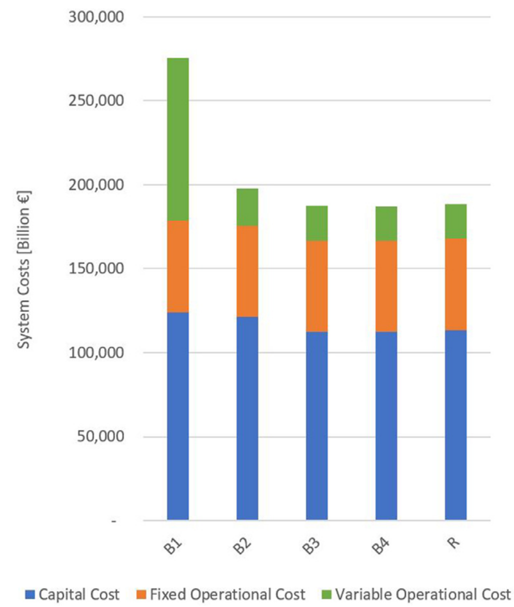

Fig. 11. Comparison of the 2050 system costs for the 5 different cases used to explore the EU power system representation in IESA-Opt. System costs in case B1 are considerably higher.

conclude that the modeling requirements are not as determinant as the computational needs. The model description does not differ depending on the number of periods considered (unless only the target year is modeled) and the data requirements also do not differ greatly (as technological learning is usually reported for the whole transition and not only for a year in particular). However, the scale of the problem can be significantly affected by the transitional choice, which might not only result in longer run times but also in the need for a larger RAM capacity and stronger CPU.

Furthermore, the transitional configuration of the model could be further strengthened by including more intermediate periods or by extending the scope of the transition further from 2050. This would increase the computational demand, while also requiring the collection of data assumptions from beyond 2050, which are not easily available.

European interconnection

The European power system representation has a more noticeable effect on the modeling results. As noted in Fig. 11, providing a dispatch representation with generation parameters (B3, B4, and B5) has a major impact on the system costs. For cases B1 and B2, where no EU interconnection and a simplistic average electricity trading price approach are used, respectively, it is possible to overestimate system costs. In addition, the abnormal difference in variable operation costs between case B1 and the others is due to the model reaching the most expensive supply option to meet the demand. This option does not satisfy the electricity demand, which leads to the assumed VOLL of 3000 €/MWh (we used the AEX price cap, although sometimes different values can be found in literature) to be a feasible alternative to reach decarbonization when external electricity is not available and when running more thermal units is not possible owing to the emissions constraint.

To understand how deeply the power interconnection formulation can permeate to other sectors, we analyzed Table 10, which compares the 2050 sectoral costs for each of the cases. It is possible to observe that, other than for cases B1 and B2, costs differ very little for most sectors. The main exception to the latter is the hydrogen sector, where cases B3 and B4 underestimated sectoral costs by 12.3% and 17.8%, respectively. This happens as a less constrained EU power system allows the accom-

Table 11
Comparison of key indicators for the integration of VRES into the system for the 5 different cases used to explore the EU power system representation in IESA-Opt.

Case	Average electricity price in 2050 [M€/PJ]	Average price variability in 2050 [M€/EJ-s]	Electricity use in 2050 [PJ]	Total curtailed electricity in 2050 [PJ]
B1	668.44	4.9	1103.82	416.41
B2	109.44	1.2	1134.33	178.34
B3	72.43	1.8	1341.80	332.97
B4	72.50	1.8	1344.22	324.18
R	76.97	1.8	1380.46	347.44

The 2050 installed capacities of wind are 112, 112, 102.4, 104.3, and 104.4 GW for scenarios B1, B2, B3, B4, and R-A3, respectively.

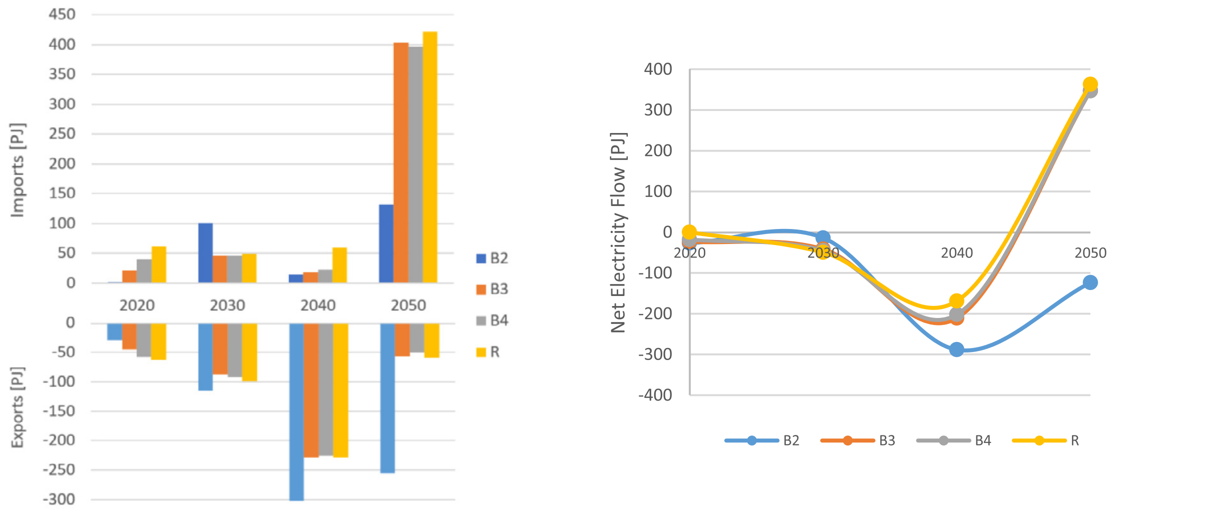

Fig. 12. Comparison of the import and export flows to explore the EU power system representation in IESA-Opt. Left: The import and export level of each case compared to the reference case (i.e. R). Right: The net electricity flow compared to the reference case.

modation of more electricity for "conflictive hours" from outside the Netherlands. The latter results in the use of only 99 PJ of electrolyzers for cases B3 and B4, lower than the 136 PJ from the reference case. This cascades to lower infrastructural needs of only 8 and 7.43 GW networks for cases B3 and B4, respectively, as compared with R. Interestingly, the latter infrastructure needs are a consequence of the required capacities for hydrogen production of 199.5, 180.1, and 232.6 PJ for cases B3, B4 and R respectively, which evidences the amount of hydrogen production shedding in the cases. This analysis is a perfect example of the usefulness of having an IEM able to simultaneously consider flexibility at an hourly resolution coupled with an EU power system to identify and measure cross-sectoral feedbacks.

The behaviors of the import and export flows, which are greatly affected by the adopted EU representation, help to further visualize the differences. Fig. 12 demonstrates that both import and export flows in B2 greatly differ from other cases; such differences tend to increase with time, mostly due to the price split that occurs as a consequence of VRES generation in the system. Additionally, the B3 formulation tends to underestimate the import and export flows even when the net difference of cases B4 and B5 is not substantial. This happens as a consequence of the European copper plate configuration, which diminishes the need for trading to alleviate both VRES excess and scarce hours. We can also notice that, up to 2040, the Netherlands evolves from a net importer to a net exporter of electricity during the transition due to the acceleration in VRES deployment in the upcoming two decades, a result which is in line with the Climate and Energy Outlook 2019 [34]. However, for the year 2050, this situation is completely reversed as a consequence of the relatively more aggressive decarbonization of the Netherlands Energy system considering other EU countries,[1] where importing electricity is accounted for by the system as a clean source of relatively cheap electricity. This is a major consequence of having an IEM that can endogenously determine electricity imports and exports. A power system model cannot provide such insights as they do not account for the emissions of the whole energy system.

Furthermore, the level of detail in the EU power system description has a direct impact on electricity prices, electrification, and curtailment. The latter indicators extracted from each case are presented in Table 11.

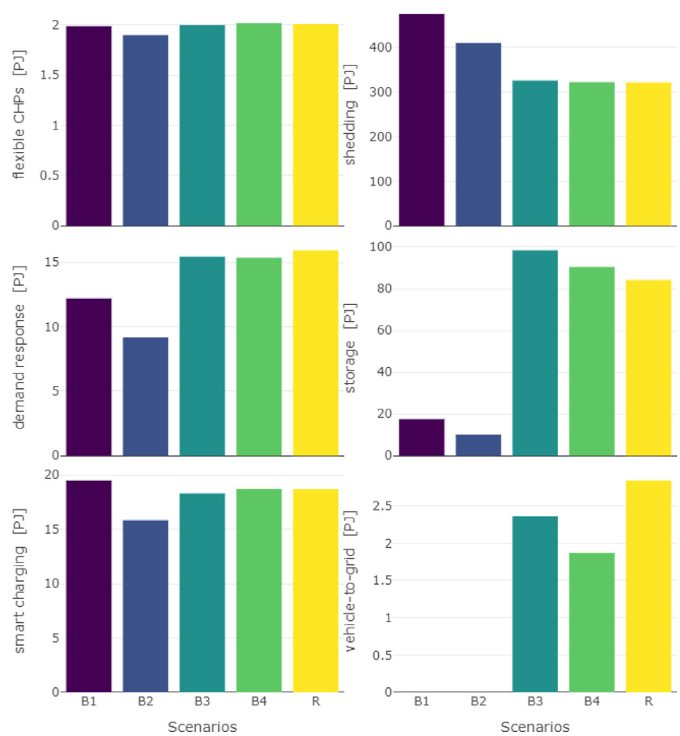

Fig. 13. Comparison of flexibility volume applied in each of the archetypes considered in IESA-Opt in 2050. In each sub-plot, the R value represents the reference case. Values are expressed in PJ of electricity per year.

The amount of electricity used in 2050 tends to increase with an increase in the level of description, where case R presents a 3% higher electrification than cases B3 and B4, and over 20% higher than cases B1 and B2. In addition, the average prices of cases B3, B4, and R are considerably lower than those of cases B1 and B2, which is in line with the substantial gaps in most of the results obtained for both groups. The curtailment in case B1 was 20% higher than in the reference case, while the other three were lower by 49%, 4%, and 7% for cases B2, B3, and B4, respectively. Similarly, the price variabilities follow a similar pattern in which cases B3, B4, and R report similar values, and B1 and B2 significantly over- and underestimate variability, respectively. These observations not only

[1] Note that the assumptions surrounding the EU energy system evolution play a key role in this observation. For a complete description of the evolution of the EU generation assets for each IESA-Opt node assumed for this study, refer to the database of the Reference Scenario available online [19].

Table 12
Electricity generation mix changes significantly across B cases.

Electricity mix [in PJ]	B1	B2	B3	B4	R
Co-fired Coal wCCS	0	0	1.8	1.7	1.4
CCGT	0	1.1	14.9	15.8	21.6
CCGT wCCS	0	0	9.4	10.1	15.3
GT	0	0	2.5	2.4	2.7
Biomass	0	0	5.6	5.3	5.1
Onshore Wind	58	57.3	56.6	56.6	56.8
Offshore Wind	790.6	774.3	756.6	756.7	766.5
Solar PV Fields	41.8	41.4	40.4	40.4	40.8
Industrial Solar PV	70	70	70	70	70
Residential Solar PV	84	84	84	84	84
Hydro	1	1	0.9	0.9	0.9
Imports	0	132.2	403.4	396.6	421.5
Exports	0	255.8	55.9	49.6	58.5
Undispatched Electricity (VOLL)	85.8	0	0	0	0

reinforce the importance of describing the generators in the EU power representation but also show that when the focus is the national energy system, acceptable results can be obtained with the simplifications proposed in B3 and B4.

As a final analysis of this topic, we show how the description of the EU interconnection impacts the adoption of flexible technologies. Fig. 13 provides the 2050 operational volumes of each of the considered flexibility archetypes in IESA-Opt in the different cases. It is possible to see that the EU interconnection description has little to no impact on a few archetypes, namely CHP's flexibility and EV's smart charging, and a moderate impact on demand response. However, for shedding, storage, and V2G, it is crucial to include the representation of the European generators, as indicated by the differences between the results obtained by cases B1 and B2 with respect to cases B3, B4, and R. In the first group of cases, shedding seems to be significantly overestimated, while storage plays a minimal role and V2G is not even present. In the second group, shedding did not differ between the three cases but storage and V2G did; however, these differences never exceeded 20%. These results are in line with previous observations, highlighting the importance of the modeling description of the EU power generators, and showing that simplifications in cases B3 and B4 can yield similar results to the more complete representation presented in the reference case.

The electricity generation mix varies significantly across B cases. In case B1, Table 12 shows a substantial amount of undispatched electricity, which is the result of a system-wide phenomenon. The main reason is the lack of "clean" electricity, as there is no imported electricity and all clean electricity sources such as wind and solar reach the maximum installed capacity constraint. Moreover, producing electricity from fossil fuel sources results in CO_2 emissions, which needs to be highly constrained by 2050. Therefore, the system cannot serve electricity at certain hours of the year, resulting in 85.8 PJ of undispatched electricity. The same situation occurs in case B2. However, owing to the availability of the import and export flexibility options, the system can export when there is excess wind and import when wind and solar profiles are at their lowest levels.

In other B cases, as the model can optimally set the electricity price, it has a higher degree of import and export flexibility. This results in substantial (clean) electricity imports at any required hour of the year, which can be used in carbon capture processes such as the P2Liquid Fischer–Tropsch process. Therefore, there is more carbon budget available for fossil-based generators such as CCGT or CCGT wCCS.

A comparison of the EU power system modeling approaches is presented in Table 13. Cases B1 and B2 overestimate system costs, while cases B3 and B4 underestimate them. However, except for case B1, these deviations are rather small, which does not necessarily mean that the solutions are good. The main interest in including a proper EU power system representation in a national model description is to correctly capture the effect that the import and export of electricity have on the operation of local supply and demand technologies. Thus, as the outcomes of cases B1 and B2 show, when the EU generators are not described as technologies with an independent (hourly) operation, the resulting system configurations differ considerably from the most detailed representation provided in the paper. Furthermore, when the independent operation of EU generators is considered, the results obtained are not strongly dependent on the number of nodes described. Nevertheless, a higher number of nodes might still provide additional insights when analyzing the role of interconnection lines with independent interconnected countries. Therefore, using fewer nodes is a viable alternative to reduce computational times (although not computational resources) while still correctly representing the national energy system configuration. It also further poses the advantages that less data must be collected and that fewer nodes must be represented in the model. However, the most extensive data requirement persists, as the total EU installed capacities for each technology are required.

Flexibility enhancements

Perhaps the most meaningful results of this study are shown in Fig. 14, where the 2050 system costs are shown for all eight cases in which IESA-Opt flexibility enhancements are explored. Here, it is possible to see that flexibility helps to decrease system costs of up to € 60.1 billion, or 24.2%, which is different between the case where no flexibility is present (C1) and where all flexibility forms are enabled (R). As mentioned, such a difference only appears for the year 2050, as before that, only 2040 shows a noticeable difference that does not exceed 3.5%. Another crucial observation is that only case C3 strongly diverges from others where only one form of flexibility is disabled; when shedding is not allowed system costs rise by € 29.4 billion (~11.8%). Similar observations can be made for the CO_2 shadow price,[2] which

[2] It is relevant to mention that CO_2 shadow prices refer to the extra system costs required to further reduce emissions by 1 Mton of CO_2, and hence do not represent the average abatement cost of CO_2.

Table 13
Overview of selected modeling elements around the EU power system representation in IESA-Opt.

Case	Objective function	Memory needs	Run time	Data requirements	Model description
B1	Sub-optimality: 45%	16 GB	66 min	Technology description of national generators	The EU power system description is omitted
B2	Sub-optimality: 3.7%	16 GB	70 min	B1 + average EU electricity prices prediction + interconnection potentials	An import and export technology
B3	Infeasibility: 1.1%	46 GB	114 min	B1 + EU generators data + EU installed capacity projections	For each extra country/node, a new activity (energy network) is required, together with the description of all the technologies in the node. Note that the EU technologies also affect the objective function, so post processing modifications are required to extract national system costs
B4	Infeasibility: 1.2%	48 GB	215 min	B3 + interconnection data with neighboring countries	
R	–	54 GB	271 min	B4 + interconnection data of all EU countries	

Fig. 14. Comparison of system costs (left) and CO2 price (right) in 2050 with the reference case (i.e. R). Eight different cases are used to explore the flexibility enhancements in IESA-Opt. By only neglecting shedding flexibility options, system costs and emission prices increase drastically.

Table 14
Sectoral decomposition of change in system costs for the eight flexibility cases.

	System Costs' change relative to R [%]							
Sector	C1	C2	C3	C4	C5	C6	C7	R [B€]
Residential	−3.1	−0.2	−0.2	−3.8	−0.6	−0.3	−0.1	21.2
Services	87.8	44.3	56.2	0.8	0.0	0.5	0.0	9.4
Agriculture	−0.1	1.8	−1.0	−0.4	−4.1	−2.5	−0.3	2.5
Industry	−0.7	−0.2	−0.8	0.4	0.0	0.0	0.0	10.9
Transport	0.2	−0.3	1.7	0.2	2.4	1.1	−0.3	72.9
Power NL	110.2	0.2	46.5	1.2	−0.6	0.3	0.1	41.6
Refineries	−31.4	1.6	−29.7	−2.9	4.9	2.9	−1.1	1.6
Heat Network	−40.9	4.5	−36.4	295.5	31.8	4.5	13.6	0.0
Final Gas	−14.6	−4.4	−6.4	1.3	1.5	0.1	1.4	3.9
Hydrogen	−57.1	−2.9	−57.1	13.1	18.3	−1.0	2.9	0.6
Fossil	2.2	0.2	2.0	−0.6	−1.1	0.4	−0.2	18.5
Others	52.5	2.9	60.3	0.9	2.4	−0.2	0.3	1.5

Table 15
Changes in the 2050 volumes of flexibility applied from the reference case to each case where a flexibility archetype is disabled.

		disabled archetypes per case					
		CHPs (C2)	Shedding (C3)	DR (C4)	Storage (C5)	SC (C7)	V2G (C8)
change in other archetypes [%]	CHPs	−100	−13.93	0.50	−2.99	0.00	0.50
	Shedding	1.20	−100	2.81	19.94	3.95	1.22
	DR	−0.63	15.12	−100	0.19	5.71	−1.19
	Storage	−0.05	42.79	3.80	−100	1.02	−0.12
	SC	−0.05	7.81	−3.53	−54.01	−100	6.74
	V2G	0.35	479.93	85.92	1343.31	357.75	−100

rises from 1944 to 8099 €/tonCO$_2$ by disabling all forms of flexibility, and to 5633 €/tonCO$_2$ when only shedding is disabled. Both arguments prove the importance of flexibility descriptions into integrated energy system analysis, as they can completely transform the resulting analysis. These results also highlight the role of shedding as a crucial flexibility archetype to include in the modeling approach. Finally, it is remarkable that the absence of most flexibility archetypes barely affects system outcomes. We can therefore conclude that most archetypes are comparable in their contribution to accommodate VRES in the system.

When analyzing the sectoral sources of the differences, we can identify four sectors in Table 14 where the main cost variations can be found: services, power, hydrogen, and heat networks. The increase in the power sector arises from the difficulties of the system to accommodate intermittent renewable sources when less cross-sectoral flexibility is available. In the case of hydrogen, when shedding is disabled, the system invests less in electrolyzers and when other flexibility forms are disabled, the system tries to compensate by investing more in hydrogen. The service sector uses CHPs for a long part of the transition and then substitutes this technology for hybrid or fully electric heat pumps. Therefore, it is very sensitive to changes in the operation of CHP systems and the stability of electricity prices. The heat network seems to be very sensitive to disabling flexibility archetypes and shows a slight correlation with the amount of hydrogen produced, which is also used as a fuel for industrial heat in this sector.

The flexibility volumes were extracted for each of the cases, and their differences with the reference case are reported in Table 15. Here, we can observe that the volume of CHP flexibility is not strongly influenced by changes in other forms of flexibility other than slightly benefiting from the presence of shedding. Furthermore, other forms of flexibility remain unchanged when CHP flexibility is disabled. Similarly, the demand response also shows little effect on the disabling of other forms of flexibility, showing a moderate increase in operation when smart charging and shedding are disabled. In the transport sector flexibility, vehicle-to-grid plays an important substitutive role for the system, showing sig-

Table 16
Comparison of key indicators for the integration of VRES into the system for the eight cases exploring flexibility enhancements in IESA-Opt.

Case	Import [PJ]	Export [PJ]	Electricity Use [PJ]	VRES Curtailment [PJ]
C1	281.2	61.9	1273.2	498.6
C2	425.2	58.3	1384.4	349.1
C3	302.2	82.2	1271.1	433.4
C4	430.8	56.4	1395.9	363.9
C5	434.2	51.8	1418.5	374.3
C6	424.8	57.8	1386.7	353.6
C7	421.4	58.1	1380.2	348.3
R	421.5	58.5	1380.4	347.5

Table 17
Electricity generation in PJ across cases C1 to C7. The overall generation mix can change considerably by neglecting flexibility options. In particular, neglecting shedding flexibility technologies can drastically affect the generation mix.

Electricity mix [in PJ]	C1	C2	C3	C4	C5	C6	C7	R
Co-fired Coal wCCS	0	1.4	0	1.5	1.8	1.4	1.5	1.4
CCGT	47	21.6	36	21.6	21.5	21.4	21.4	21.6
CCGT wCCS	12.7	15.3	20	15.4	15.3	15.4	15.2	15.3
GT	0	2.6	0	3.3	3.3	3.1	2.7	2.7
Biomass	0	5.2	0	6.2	6.4	5.8	5	5.1
Onshore Wind	52.9	56.8	55.4	57	57	56.8	56.9	56.8
Offshore Wind	726.2	767	779.9	770.7	768.2	767.9	766.5	766.5
Solar PV Fields	30.4	40.8	38.3	41	41	40.8	40.9	40.8
Industrial Solar PV	70	70	70	70	70	70	70	70
Residential Solar PV	84	84	84	84	84	84	84	84
Hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Imports	281.2	425.2	302.2	430.8	434.2	424.8	421.4	421.5
Exports	61.9	58.3	82.2	56.4	51.8	57.8	58.1	58.5
Undispatched Electricity (VOLL)	55.7	0	19.9	0	0.1	0	0	0

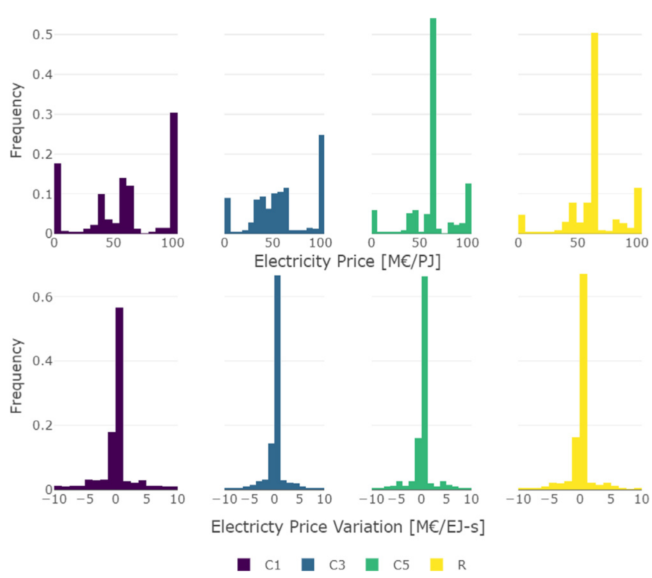

Fig. 15. Comparison of the electricity price and variability histograms for cases C1, C3 and R.

nificant increments upon the disabling of the other archetypes (except CHPs). In addition, smart charging strongly benefits from the presence of storage in the system, and further develops when shedding and V2G are disabled. Finally, storage and shedding show the most pronounced effect on other forms of flexibility. When shedding is disabled, other forms of flexibility (except CHPs) increase their contribution substantially, and when storage is disabled, all other forms of flexibility decrease their contribution (except shedding).

Another relevant aspect to explore is the impact of disabling flexibility in electricity prices. A considerable difference is not present in price behaviors between the reference case and most cases, but cases C1, C3, and C5 present significant differences worth mentioning. To further explore the differences, the histograms of the electricity prices and price variability were extracted for cases C1, C3, C5, and R and are presented in Fig. 15. Here, it is possible to see that when no flexibility is present in the system (C1), there is a large amount of extremely low and extremely high price events (roughly half of the total events). By applying all forms of flexibility, the extreme price events decrease to less than 15%, and price variability is significantly decreased. When shedding is disabled, C3, there is still a considerable number of extreme price events (roughly 33%), while the price variability histogram still significantly resembles the reference case with a slight decrease in extreme variability events. When storage is disabled, as in C5, the histograms still resemble that of the reference case, with the difference being a valley of low price events under 50 M€/PJ. From these observations, we can notice that shedding plays a key role in mitigating extreme price events and storage plays a key role in distributing the moderate price events more evenly. These results highlight the paramount importance of flexible demand in electricity dispatching.

The final observation of this section explores the interaction of flexibility enhancements with the import and export of electricity and the impact on system electrification and VRES curtailment. As shown in Table 16, similar results are extracted, where the absence of flexibility impacts the results severely by decreasing imports by 33% and increasing the amount of renewable electricity curtailed by 43%. For cases where flexibility enhancements are removed progressively, the absence of shedding (C3) and storage (C5) result in greater deviations from the reference case by increasing curtailed renewable electricity by 25% and 8%, respectively, and changes in the electricity exports of 43% and −11%, respectively. Higher electrification is achieved when storage is disabled, followed by the disabling of demand response and CHP flexibility, while lower electrification occurs for cases C1 and C3, with sub-

Table 18
Overview of selected modeling elements of the eight cross-sectoral flexibility cases in IESA-Opt.

Case	Objective function	Memory needs	Run time	Data requirements	Model description
C1	Sub-optimality: 31%	43 GB	86 min	No further data required	No flexibility description
C2	Sub-optimality: 1.6%	48 GB	168 min	All except CHPs operation zones	Each capability requires its own
C3	Sub-optimality: 16%	48 GB	155 min	All except shedding capacity and non-negotiable loads	flexibility formulation accordingly with presented in the IESA-Opt paper
C4	No difference	50 GB	205 min	All except share of flexible demand, and non-negotiable loads	{cite the IESA-Opt paper after the revision}
C5	Sub-optimality: 0.6%	51 GB	224 min	All except charging rates, storage capacities and efficiencies	
C6	Sub-optimality: 0.2%	50 GB	150 min	All except electric vehicles operation profiles, charging and storage capacities	
C7	No difference	50 GB	172 min	All except electric vehicles operation profiles, charging, storage capacity and efficiencies	
R	–	54 GB	270 min	All	All of the above

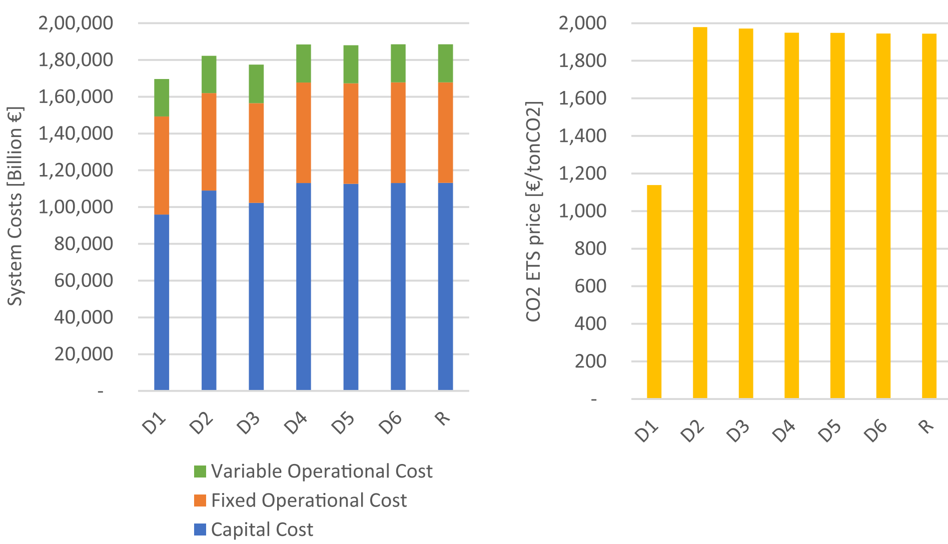

Fig. 16. Comparison of the system costs (left) and CO2 piece (right) in 2050 for the seven cases used to explore the infrastructure representation in IESA-Opt. Assuming a freely connected energy network in case D1 can drastically reduce emission prices.

stantial reductions of 8% for both cases. Disabling other flexibility forms resulted in a marginal impact on the reference case, except for a slight increase in curtailment of 5% when demand response is absent (C4). As a general observation, the presence of different forms of flexibility tend to have a low impact on electricity trading, except for shedding and storage, and contributes significantly to decreasing VRES curtailment.

The electricity mix in 2050 can change considerably depending on the consideration of different flexibility options (see Table 17). Neglecting flexibility options results in a drastic increase of 55.7 PJ in undispatched electricity compared to the reference case. This can be explained by the inter-sectoral interactions in the energy system. As there is no flexibility option, the supply and demand for electricity cannot deviate from a reference profile. Although there are import and export options, the system cannot compensate for all the missing generation with these. Moreover, the system cannot use shedding technologies, which drastically electrify the industry and reduce emissions. The lack of shedding technologies pushes the system to choose non-electrified substitutes to meet industrial demand. Therefore, the system is highly constrained in the carbon budget and cannot invest enough in fossil peak shaver generators such as gas turbines. A similar reasoning applies in case 3, in which the undispatched electricity is lower than C1 because other flexibility options can provide supply and demand flexibility to some extent. The absence of other flexibility archetypes does not considerably affect the generation mix.

It should be noted that the hourly wind and solar profiles remain the same for all cases. This results in very low electricity generation from wind and solar sources at certain hours of the year. In case of the lack of flexibility options, the system invests in extra peak load capacity, such as gas turbines, which are expensive and polluting.

Two main conclusions can be drawn from this experiment. First, representing operational flexibility outside the power dispatch is important for correctly accounting for technological options that can help to make the energy transition substantially more affordable. Second, shedding (mainly represented as electrolyzers for the hydrogen network and electrolyzers for ammonia production and refineries) is the key form of flexibility to include in the energy system representation. These conclusions are supported by all results presented in this section, as well as by the objective function value as presented in Table 18, and are in line with studies pointing towards shedding and shifting as the two more cost-effective options [37]. It can be observed that the absence of cross-sectoral flexibility representation often leads to sub-optimal solutions, leading to overestimations of transitional costs. However, such capabilities come at a high computational price, as they can together increase computational times up to 314%, albeit without the need for additional memory. Nevertheless, if swift solutions are needed and no specific sectoral transport analysis is required, we recommend skipping electric vehicle flexible capabilities, as they do not have a major influence on the results, and they require more time to solve owing to the strong impact of the variable available capacity inherent to their operational profiles.

Another sensible element of the cross-sectoral flexibility formulation relates to the availability of data. The IESA-Opt proposed formulation {cite the IESA-Opt paper after the revision} requires extra data representing the extent and duration for which the operation of flexible technologies is shed or delayed. These data are usually available or can be reliably inferred only for well-described technologies such as electrolyzers, batteries, storage tanks, electric vehicles, and some industrial processes. However, some other technologies such as generic demand response in the residential sector require assumptions or further technological disaggregation, which might result in either extra uncertainties or further model complexity. In particular, for IESA-Opt, it is recommended that special attention should be paid to these parameters when further developing the model.

Infrastructure representation

The impact of considering infrastructure technologies such as transmission lines, transformers, and compressors can be observed in Fig. 16, where the system cost of 2050 is compared for the cases with different infrastructure forms considered. The first observation is that the representation of infrastructure can greatly affect system costs, particularly the capital component, as a difference of 10% can be observed between cases D1 and R. The second observation is that only the electricity and gas network representation affect system costs significantly, as the system results are 3.3% and 5.9% cheaper, respectively. The volume of development of hydrogen, district heating, and CCUS networks is considerably lower regarding gas and electricity, which in combination with the long economic lifetime of the infrastructure technologies, makes their impact on the total system costs of 2050 remain well below one billion euro per year.

When evaluating the sectoral costs reported in Table 19, we found that cases D4, D5, D6, and R present almost no differences other than direct effects in their own sectors. On the other hand, cases D1, D2, and D3 present significant differences in costs. We can see that residential, service, and industrial sectors present considerably lower system costs, which is a consequence of adopting district heating and hydrogen technologies. In addition, the use of gas and electricity is 343 and 2556 PJ in D1 and 405 and 1869 PJ in D3, respectively, which, in contrast to the 325 and 1557 PJ, respectively, of the reference case, shows that omitting the complete infrastructure description might result in an overestimation of electrification, district heating, gas, and hydrogen as decarbonization activities.

As seen in Table 20, the most notorious case of feedback on other energy carrier infrastructure occurs in the absence of natural gas infrastructure description, where the required transformer capacities decrease owing to the higher flexibility provided to the system by underconstrained gas generators. However, this does not mean that the lack of infrastructure representation does not affect the system configuration in other sectors. An example of the latter is what happens in the production of synthetic fuels when the electricity infrastructure is not represented, as its absence decreases the amount of methanol produced from 188 to 153 PJ as the role of P2Liquid technology for avoiding network congestion events is no longer necessary. Similar examples are found in the volume of electrolyzers and district heating deployed in 2050, as the role of both technologies is greatly overestimated when no infrastructure representation is provided in the model.

The electricity generation mix can change drastically if the infrastructure constraints are neglected. In case D1, where the national transmission lines are considered as a copper plate, the model invests heavily (i.e., 97 GW) in offshore wind energy because the model does not need to invest in transmission lines between the offshore grid and the national

Table 19
Sectoral decomposition of system costs' change for the seven infrastructure cases.

Sector	System Costs' change relative to R [%] D1	D2	D3	D4	D5	D6	R [B€]
Residential	−16.6	−0.1	−11.7	−0.1	−0.3	−0.3	21.2
Services	−29.9	0.6	−30.3	0.5	0.7	−0.4	9.4
Agriculture	−6.4	0.1	4.0	0.0	2.6	0.8	2.5
Industry	−24.3	1.4	−28.2	0.1	−2.4	−0.2	10.9
Transport	−0.2	0.2	−0.2	0.0	0.0	0.0	72.9
Power NL	−12.5	−14.3	−1.5	0.2	0.1	0.0	41.6
Refineries	−43.5	−19.7	7.2	−2.0	1.3	0.6	1.6
Heat Network	886.4	−4.5	531.8	4.5	18.2	131.8	0.0
Final Gas	−61.5	−1.0	−61.5	−0.4	0.5	0.8	3.9
Hydrogen	178.2	37.0	−8.9	−31.3	−0.7	−0.7	0.6
Fossil	−1.8	−2.1	3.1	−0.3	0.1	0.1	18.5
Others	−52.4	−3.5	−22.3	−0.1	−29.7	0.0	1.5

Table 20
Installed capacities of infrastructure technologies in 2050 for the different cases.

Carrier	Technology	Units	D1	D2	D3	D4	D5	D6	R
Electricity	Transformer from LV to HV	GW	–	–	0.6	0.2	0.1	0.2	0.2
	Transformer from MV to HV	GW	–	–	4.4	5.0	5.2	5.1	5.1
	Transformer from HV to MV Baseload	GW	–	–	4.0	4.6	4.4	4.5	4.5
	Transformer from HV to MV Peaks	GW	–	–	9.0	9.5	9.4	9.4	9.4
	Transformer from LV to MV	GW	–	–	0.4	0.1	0.1	0.1	0.1
	Transformer from HV to LV	GW	–	–	8.3	7.8	7.9	7.9	7.8
	Transformer from MV to LV Peaks	GW	–	–	4.2	4.7	4.7	4.7	4.7
	HV Electricity grid cable	GW	–	–	39.9	39.9	40.1	39.9	39.9
	MV Electricity grid cable	GW	–	–	13.9	14.0	14.0	13.9	13.9
	LV Electricity grid cable	GW	–	–	13.9	13.9	13.9	13.9	13.9
Natural gas	HD to MD natural gas compressor	GW	–	46.1	–	46.7	46.6	46.7	46.7
	MD to LD natural gas compressor	GW	–	41.3	–	41.8	41.7	41.8	41.8
	Natural gas HD grid pipeline	GW	–	81.8	–	81.9	83.1	81.5	81.5
	Natural gas MD grid pipeline	GW	–	62.5	–	63.3	63.5	63.3	63.3
	Natural gas LD grid pipeline	GW	–	50.0	–	50.0	50.0	50.0	50.0
Hydrogen	HD to LD hydrogen compressor	GW	–	0.6	0.6	–	0.6	0.6	0.6
	Hydrogen HD grid pipeline	GW	–	1.8	1.5	–	1.4	1.5	1.5
	Hydrogen LD grid pipeline	GW	–	0.6	0.6	–	0.6	0.6	0.6
CCUS	CCUS grid pipeline	Mm	–	2.0	2.0	2.0	–	2.0	2.0
Heat	LT Heat network pipeline	Mm	–	0.7	0.7	0.7	0.7	–	0.7

Table 21
Electricity generation in PJ across cases D1 to D6. The overall generation mix does not change considerably, except the considerable change in case D1 where infrastructure is neglected in the model.

Electricity mix [in PJ]	D1	D2	D3	D4	D5	D6	R
Co-fired Coal wCCS	1.45	1.35	1.37	1.4	1.42	1.41	1.41
CCGT	19.86	20.57	20.41	21.43	21.57	21.59	21.59
CCGT wCCS	13.91	15.29	14.38	15.28	15.28	15.3	15.31
GT	1.75	2.32	2.26	2.64	2.63	2.66	2.66
Biomass	4.92	4.83	4.61	5	5.17	5.07	5.09
Onshore Wind	58.39	58.4	56.88	56.96	56.88	56.85	56.84
Offshore Wind	1195.68	767.89	766.21	767.56	767.9	767.1	766.53
Solar PV Fields	42	42	40.83	40.96	40.78	40.81	40.82
Industrial Solar PV	70	70	70	70	70	70	70
Residential Solar PV	84	84	84	84	84	84	84
Hydro	0.95	0.95	0.92	0.93	0.92	0.93	0.93
Imports	182.63	427.92	438.71	421.91	420.37	420.88	421.48
Exports	228.92	59.98	56.84	57.21	57.57	57.4	57.39

Table 22
Overview of selected modeling elements of the infrastructure representation in IESA-Opt.

Case	Objective function	Memory needs	Run time	Data requirements	Model description
D1	Infeasibility: 10%	48 GB	161 min	No further data required	No flexibility description
D2	Infeasibility: 3.7%	51 GB	179 min	Electricity infrastructure and transformers costs, efficiencies and potentials	Each capability requires a supply and demand balance in the network for the considered dispatch resolution, as well as a maximum activity constrained by the infrastructure installed capacity. The complete formulation is presented in the IESA-Opt paper {cite the IESA-Opt paper after the revision}
D3	Infeasibility: 5.8%	50 GB	174 min	Gas infrastructure and compressors costs and potentials	
D4	No difference	51 GB	231 min	Hydrogen infrastructure and compressors costs and potentials	
D5	Infeasibility: 0.3%	50 GB	189 min	CCUS network infrastructure costs and potentials	
D6	No difference	50 GB	220 min	Heat network infrastructure costs and potentials	
R	–	54 GB	270 min	All of the above	All of the above

grid. Moreover, there is no grid loss due to the copper plate assumption. Therefore, investing in offshore wind capacity becomes cheaper than importing electricity from neighboring countries, which includes grid losses and investment in transition lines over the imported electricity price. Table 21 shows that apart from case D1, the generation mix shows negligible differences across other D cases.

As seen in Table 22, the main conclusion to be extracted from these experiments is that it is extremely important to correctly represent electricity and natural gas network infrastructure. When their representation is neglected, the results tend to underestimate system costs significantly and overestimate the role of key technologies such as electrolyzers. The other infrastructure representations (i.e., hydrogen, CCUS, and heat distribution networks) present a very limited effect in the system representation. The lack of representation of hydrogen and heat distribution networks results in a slight overestimation of the adoption of these technologies. On the other hand, the lack of a CCUS network description has little to no effect on the system outcome. Owing to the emission constraint being stringent, even when infrastructure costs are accounted for, the full potential of CO_2 storage and captured CO_2 reutilization are already reached. Therefore, if the computational time needs to be reduced, it is recommended to adopt an approach in which the infrastructure costs of the hydrogen, CCUS, and heat distribution networks are considered without describing the operational constraint imposed on the system, as this would reduce the problem complexity without considerably sacrificing solution quality.

Another aspect to consider is that representing infrastructure in a model requires an intricate data collection process, as many costs and operational parameters are spatially sensitive (i.e., a gas pipeline in a mountain range is more expensive than in a plain). IESA-Opt still has a large scope for improvement in this regard, as better data availability could enable the representation of intriguing transitional options such as industrial clusters for heat recirculation or district heating purposes, or even for hydrogen or CO_2 users. However, even when this data is available at a sufficient quality, representing the role of these alternatives in the model to further decrease decarbonization costs would require a tailored formulation according to the specific designs of possible projects. This type of potential application can allow IEMs to be used as test fields for clustering and infrastructure design.

Computational resources

It is logical to infer that by enabling a larger set of capabilities into the model, both solving time and computational affordability[3] are further compromised, both of which are crucial aspects when expanding problem analysis. To discuss the latter impact of the cases explored in this study, we report the computational times, memory requirements, and the resulting problem size (after pre-solving) for all the cases in Table 23.

For the family of A cases, the memory requirements and problem size seem to grow linearly with the introduction of each period, as indicated by the computational times. However, the last observation might be biased by the size of the RAM used as the number of hard-faults increased with larger problems, which made the calculation slower.

For the family of B cases, the complexity of the problem is not correlated with the problem size, as the problem sizes of B1 and B2, as well as those of B3 and B4, do not differ greatly. However, as expected, the computational times increase with the complexity of the capabilities included in the cases. From the family of B cases, it is worth highlighting case B3, which yields suitable results at a national level and can run considerably faster than cases B4 and R.

[3] By computational affordability, we refer to the ability to solve a computational problem without the need for out-of-norm processors or memories.

Table 23
Computational requirements of the mathematical problems resulting from the formulation of the different cases explored. Bold numbers refere to the reference case.

Case	Time [min]	# Variables [1e6]	# Constraints [1e6]	# Non-zeros [1e6]	Memory [GB]
A1	30.9	2.1	3.4	16.1	13.0
A2	114.6	4.9	7.3	34.7	27.5
R-A3	**270.7**	**10.2**	**14.7**	**69.1**	**53.5**
A4	456	18.5	26.1	125.2	88.2
B1	65.7	4.5	2.6	29.2	16.0
B2	69.2	4.5	2.7	29.5	16.0
B3	113.7	9.5	12.0	63.7	45.9
B4	214.7	9.7	13.2	66.1	47.7
C1	85.9	7.3	13.1	53.5	43.1
C2	167.5	8.9	14.1	61.9	48.2
C3	155.3	9.7	14.5	66.8	48.3
C4	205.4	10.1	14.6	68.0	50.1
C5	224.2	9.9	14.5	67.8	50.5
C6	150	9.8	14.4	66.8	49.7
C7	172	10.1	14.6	68.3	50.2
D1	160.6	9.7	14.5	62.6	48.4
D2	179	10.1	14.7	64.6	51.4
D3	173.6	10.2	14.7	68.6	50.3
D4	231.4	10.2	14.7	69.1	51.0
D5	189.3	10.2	14.7	68.8	50.3
D6	220.6	10.2	14.7	69.0	50.4

Next, for the family of C cases, it is highly noticeable that, by disabling flexibility, the problem becomes smaller and solves faster. One can perceive that the three flexibility enhancements with the most computational requirements are Shedding, V-to-G, and Smart Charging, while storage and demand response have the lowest impact on computational times.

A similar observation can be extracted for D cases, where disabling infrastructure representation decreases problem size and solving times. For these cases, gas and electricity infrastructures impose the highest burden on the solution, while hydrogen and district heating infrastructure affect the problem size and times the least.

Finally, it is important to mention that IESA-Opt's mathematical problem is formulated in AIMMS [38]. It is solved with the Gurobi 9.01 solver via the barrier method using a laptop with 32 GB of RAM and an Intel i8750-H processor. It should be noted that we used an average laptop to perform the analysis. However, with the aid of more powerful hardware, the computational times can be further reduced, especially for larger problems. This could allow the further expansion of the problem or the use of multiple runs to perform sensitivity analyses under practical timeframes.

Discussion

Twenty-one cases were presented in this study to analyze the effect of the level of granularity in four modeling capabilities on several system configuration indicators. The main takeaways can be summarized as follows:

Transitional scope

We can conclude that considering the goals of the study, fewer transitional periods can be included to save computational time and resources at the expense of providing cost underestimations (i.e., infeasibilities). This simplification does not affect the system costs and CO_2 prices considerably. Moreover, it reduces the computational load, resulting in much shorter run times and the reduced need for a costly computer. However, the model description and data requirements do not differ considerably by changing the number of periods considered. The transitional scope of the model could be extended further than in 2050. This would increase the computational demand while requiring the collection of data assumptions for beyond 2050, which is not easily available.

European interconnection

The main need to include an EU power system representation in a national model is for correctly capturing the effect of the import and export of electricity on the operation of local supply and demand. By considering the independent operation of EU generators, the main system indicators do not change significantly with the number of described nodes. Therefore, as long as a dispatchable European node is considered, using fewer nodes is a practical alternative to reduce computational loads while leading to minor deviations in the results from the full node representation. Moreover, it has the advantage that fewer nodal data need to be collected.

Flexibility enhancements

Representing operational flexibility outside the power dispatch is important for correctly accounting for technological options that can make the energy transition substantially more affordable. Moreover, shedding was identified as the key form of flexibility for cases with a high share of intermittent renewables. The presence of different forms of flexibility tends to significantly decrease the curtailment of intermittent renewables and has a low impact on electricity trading, except for shedding and storage. Moreover, the absence of cross-sectoral flexibility representation often leads to sub-optimal solutions, resulting in overestimations of transitional costs. Additionally, if electric vehicle analysis is not considered, we can neglect their flexibility as it requires substantial computational resources while having no significant influence on the system-wide results. Although flexibility data for well-described technologies are usually available, some other technologies such as the generic demand response in the residential sector require assumptions or further technological disaggregation, which result in uncertainties or further model complexity.

Infrastructure representation

By avoiding the representation of the electricity and natural gas network infrastructure, the results tend to underestimate system costs significantly and overestimate the role of key technologies such as electrolyzers. Other infrastructure representations, namely, hydrogen and carbon capture, utilization, and storage (CCUS), as well as heat distribution networks, have a very limited effect on the system representation. However, the lack of representation of the hydrogen and heat distribution networks results in slight overestimations in the adoption of these technologies. The lack of a CCUS network description has a negligible effect on the system outcome because the emission constraint is so stringent that the full potential of CO_2 storage and captured CO_2 reutilization are already considered. Therefore, to reduce computational time, it is recommended to consider the infrastructure costs of the hydrogen, CCUS, and heat distribution networks without describing the operational constraints imposed on the system.

Representing infrastructure parameters requires an intricate data collection process, as many of the cost and operational parameters are spatially sensitive. Energy system models can further improve in this aspect as better data availability could enable the representation of transitional options such as heat recirculation in industrial clusters, district heating, hydrogen, or CO_2 consumers. However, even when this data would be available at a required quality, representing the role of these alternatives would require a tailored formulation according to the specific goals of the project.

Computational load

The memory requirements and problem size seem to grow linearly with higher granularities in the transitional scope, similarly with the computational times. Moreover, the three flexibility enhancements with the most computational requirements were identified as shedding, vehicle-to-grid, and smart charging, while storage and demand response had the lowest impact on computational times. Furthermore, the representation of gas and electricity infrastructure imposes the highest burden on the solution, while hydrogen and district heating infrastructure affect the problem size and times the least.

The computational time of a mathematical problem can be reduced by either hardware or software improvements. To include higher details while maintaining low solving times, the hardware can be improved, as we used a relatively affordable laptop for this study. On the other hand, we presented several model-specific methods for improving computational times, while using a state-of-the-art solver configuration. These model-specific methods come with their own set of trade-offs, as explained earlier. It is recommended for modelers to set the computational expectations of the model based on the focus of the study.

Conclusion

In this paper, we quantified some modeling trade-offs by employing an applied energy system model that covers all energy sectors, includes grid infrastructure, and integrates a transnational linear power system representation that includes cross-border trade. We generated 21 cases based on a reference scenario of the Netherlands as a case study, while the results can be interpreted for other similar national energy systems. We measured the cost of increasing resolution in each modeling capability in terms of computational time and energy system modeling indicators, notably, system costs, emission prices, electricity generation, and import and export levels.

Our findings can be summarized as: First, reducing the transitional scope from seven to two periods can reduce the computational time by 75% while underestimating the objective function by only 4.6%. Second, if the electricity trade with each neighboring country is not the focus of the study, modelers can assume a single EU node that dispatches electricity at an aggregated level (while still describing the distribution of the technologies taking part in the dispatch). This assumption underestimates the objective function by 1% while halving the computational time. Furthermore, shedding technologies (such as electrolyzers) and storage options are a must for any integrated energy system with high shares of variable renewable energy, as their absence can strongly affect modeling outcomes in terms of the objective function, system configuration, and operation of technologies. In general, neglecting flexibility options can drastically decrease the computational time but can increase the sub-optimality by up to 31%. Finally, while reducing the computational time to half, the lack of electricity and gas infrastructure representation can underestimate the objective function by 4% and 6%, respectively.

This study comes with some shortcomings. For instance, we assumed flat profile for a considerable number of technology options, while hourly load profiles can play an important role in determining the optimal portfolio of technologies. Acquiring hourly load profiles for each technology and energy source (e.g., wind and sun) can be a challenge. Therefore, modelers may assume the same profile for a set of technologies, or use clustering methods in data preprocessing. It is highly suggested to analyze the impact of input data resolution on modeling results and computational loads (Table 8).

This paper can guide energy system modelers to better frame their modeling assumptions based on the focus of their study. The quantified modeling trade-offs presented in this paper, can be used by other energy system modelers to better identify crucial computational gaps. Moreover, energy modelers can realize the quantified importance of analyzed modeling capabilities on accuracy of final results.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

The authors would like to thank Klara Schure and Robert Koelemeijer from PBL (the Netherlands Environmental Agency) for their efforts in developing the ENSYSI model, which played an important role in the creation of the IESA-Opt model. Furthermore, we want to thank other members of the Energy Transition team at TNO for their help and guidance.

The authors wish to acknowledge the support provided by the ESTRAC Integrated Energy System Analysis project financed by the New Energy Coalition (finance code: 656039). The views expressed here are those of the authors alone and do not necessarily reflect the views of the project partners or the policies of the funding partners.

References

[1] I. Hidalgo González, P.R. Castello, A. Sgobbi, W. Nijs, S. Quoilin, A. Zucker, et al., “Addressing flexibility in energy system models 2015 Report EUR 27183 EN,” 2015, doi: 10.2790/925.
[2] Reuß M, Grube T, Robinius M, Stolten D. A hydrogen supply chain with spatial resolution: comparative analysis of infrastructure technologies in Germany. Appl Energy Aug. 2019;247:438–53. doi:10.1016/j.apenergy.2019.04.064.
[3] Von Appen J, Braun M. Sizing and improved grid integration of residential PV systems with heat pumps and battery storage systems. IEEE Trans Energy Convers Mar. 2019;34(1):562–71. doi:10.1109/TEC.2019.2892396.
[4] Schmid E, Knopf B, Pechan A. Putting an energy system transformation into practice: the case of the German energiewende. Energy Res Soc Sci Jan. 2016;11:263–75. doi:10.1016/j.erss.2015.11.002.
[5] Koltsaklis NE, Dagoumas AS, Kopanos GM, Pistikopoulos EN, Georgiadis MC. A spatial multi-period long-term energy planning model: a case study of the Greek power system. Appl Energy Feb. 2014;115:456–82. doi:10.1016/j.apenergy.2013.10.042.
[6] Welsch M, Deane P, Howells M, Gallachóir BO, Rogan F, Bazilian M, et al. Incorporating flexibility requirements into long-term energy system models - a case study on high levels of renewable electricity penetration in Ireland. Appl Energy Dec. 2014;135:600–15. doi:10.1016/j.apenergy.2014.08.072.
[7] Ludig S, Haller M, Schmid E, Bauer N. Fluctuating renewables in a long-term climate change mitigation strategy. Energy Nov. 2011;36(11):6674–85. doi:10.1016/j.energy.2011.08.021.
[8] M. Nicolosi, Mills, A. D; Wiser R., “The importance of high temporal resolution in modeling renewable energy penetration scenarios,” 2010.
[9] Frew BA, Jacobson MZ. Temporal and spatial tradeoffs in power system modeling with assumptions about storage: an application of the POWER model. Energy 2016;117:198–213. doi:10.1016/j.energy.2016.10.074.
[10] Poncelet K, Delarue E, Six D, Duerinck J, D’haeseleer W. Impact of the level of temporal and operational detail in energy-system planning models. Appl Energy 2016;162:631–43. doi:10.1016/j.apenergy.2015.10.100.
[11] Haydt G, Leal V, Pina A, Silva CA. The relevance of the energy resource dynamics in the mid/long-term energy planning models. Renew Energy 2011;36(11):3068–74. doi:10.1016/j.renene.2011.03.028.

[12] Deane JP, Chiodi A, Gargiulo M, Ó Gallachóir BP. Soft-linking of a power systems model to an energy systems model. Energy 2012;42(1):303–12. doi:10.1016/j.energy.2012.03.052.
[13] Fattahi A, Sijm J, Faaij A. A systemic approach to analyze integrated energy system modeling tools, a review of national models. Renew Sustain Energy Rev 2020.
[14] Pattupara R, Kannan R. Alternative low-carbon electricity pathways in Switzerland and it's neighbouring countries under a nuclear phase-out scenario. Appl Energy Jun. 2016;172:152–68. doi:10.1016/j.apenergy.2016.03.084.
[15] Mertens T, Poncelet K, Duerinck J, Delarue E. Representing cross-border trade of electricity in long-term energy-system optimization models with a limited geographical scope. Appl Energy Mar. 2020;261:114376. doi:10.1016/j.apenergy.2019.114376.
[16] Holttinen H, Meibom P, Orths A, Lange B, O'Malley M, Tande JO, et al. Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration. Wind Energy Mar. 2011;14(2):179–92. doi:10.1002/we.410.
[17] Blanco H, Faaij A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. Renew Sustain Energy Rev Jan. 01, 2018;81:1049–86 Elsevier Ltd. doi:10.1016/j.rser.2017.07.062.
[18] Blanco H, Nijs W, Ruf J, Faaij A. Potential for hydrogen and power-to-liquid in a low-carbon EU energy system using cost optimization. Appl Energy Dec. 2018;232:617–39. doi:10.1016/j.apenergy.2018.09.216.
[19] Fattahi A, Sanchez Dieguez M, https://energy.nl/iesa/.
[20] Cebulla F, Fichter T. Merit order or unit-commitment: how does thermal power plant modeling affect storage demand in energy system models? Renew Energy May 2017;105:117–32. doi:10.1016/j.renene.2016.12.043.
[21] Zhang L, Capuder T, Mancarella P. Unified unit commitment formulation and fast multi-service LP model for flexibility evaluation in sustainable power systems. IEEE Trans Sustain Energy Apr. 2016;7(2):658–71. doi:10.1109/TSTE.2015.2497411.
[22] L. Mantzos, T. Wiesenthal, F. Neuwahl, and M. Rózsai, "The POTEnCIA. Central scenario. An EU energy outlook to 2050," 2019. doi: 10.2760/78212.
[23] European Commission. Directorate-general for economic and financial affairs., "The 2018 ageing report economic & budgetary projections for the 28 EU member states (2016-2070).," Institutional Paper 079., Brussels., 2018. doi: 10.2765/615631.
[24] Riahi K, van Vuuren DP, Kriegler E, Edmonds J, O'Neill BC, Fujimori S, et al. The shared socioeconomic pathways and their energy, land use, and greenhouse gas emissions implications: an overview. Glob Environ Change Jan. 2017;42:153–68. doi:10.1016/j.gloenvcha.2016.05.009.
[25] Ruiz P, Sgobbi A, Nijs WN, Thiel C, Dalla Longa F, Kober T, et al. The JRC-EU-times model : bioenergy potentials for EU and neighbouring countries. Publications Office; 2015.
[26] "Ministry of economic affairs and climate policy integrated national energy and climate plan," 2021.
[27] "Nuclear energy | Renewable energy | Government.nl." https://www.government.nl/topics/renewable-energy/nuclear-energy (accessed Jun. 20, 2020).
[28] P. Planbureau voor de Leefomgeving, "Efecten van de energietransitie op de regionale arbeidsmarkt- - een quickscan."
[29] TNO, "Technology factsheets database," 2020. https://energy.nl/en/search/?fwp_content_type=factsheets (accessed Mar. 10, 2020).
[30] Özdemir Ö, Hobbs BF, van Hout M, Koutstaal PR. Capacity vs energy subsidies for promoting renewable investment: benefits and costs for the EU power market. Energy Policy Feb. 2020;137:111166. doi:10.1016/j.enpol.2019.111166.
[31] Entsog and Entso-e, "TYNDP Scenario Report 2020," 2020.
[32] Spinoni J, Vogt JV, Barbosa P, Dosio A, McCormick N, Bigano A, et al. Changes of heating and cooling degree-days in Europe from 1981 to 2100. Int J Climatol Apr. 2018;38:e191–208. doi:10.1002/joc.5362.
[33] "JRC POTEnCIA. Central scenario | EU Science Hub." https://ec.europa.eu/jrc/en/potencia/central-scenario (accessed Mar. 09, 2020).
[34] PBL Climate and energy outlook 2019. The Hague; 2019. Accessed: Mar. 09, 2020. [Online]. Available: www.pbl.nl/kev.
[35] C. PBL Valuation of CO_2 emissions in CBA: implications of the scenario study welfare, prosperity and the human environment. The Hague; 2016.
[36] "JRC Data Catalogue. ENSPRESO, biomass. - European Commission." https://data.jrc.ec.europa.eu/dataset/74ed5a04-7d74-4807-9eab-b94774309d9f/resource/94aca7d6-89af-4969-a74c-2c7ab4376788 (accessed Mar. 09, 2020).
[37] Brouwer AS, van den Broek M, Zappa W, Turkenburg WC, Faaij A. Least-cost options for integrating intermittent renewables in low-carbon power systems. Appl Energy Jan. 2016;161:48–74. doi:10.1016/j.apenergy.2015.09.090.
[38] "AIMMS version 4.74, " *Copyright © 2020 AIMMS B.V. All rights reserved.*https://www.aimms.com/.