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Energy System Analysis of thermal, hydrogen and battery storage in the energy system of Sweden in 2045

POORNIMA SUNDARRAJAN

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Poornima Sundarrajan

Approved	Examiner	Supervisors
	Prof. Viktoria Martin	Main Supervisor - Jagruti R. Thakur, PhD Co- Supervisor – Drilon Meha, PhD (University of Pristina)
	Industrial Supervisor	Contact person
		Jagruti R. Thakur, PhD

Abstract

Sweden has goals to reach net-zero emissions by 2045. Although electricity sector is almost fossil free, industry & transport still rely on fossil fuels. Ambitious initiatives such as HYBRIT, growth of EV market & expansion of wind power aim to expedite emission reduction. Decarbonization of transport, industry and large-scale wind & solar PV integration in the future necessitates studying energy system of Sweden at national scale in the context of sector coupling, external transmission & storage technologies.

Therefore, this study aims to evaluate the impact of thermal energy storage, hydrogen storage and batteries via Power-to-heat & Power-to-hydrogen strategies in the future Swedish energy system (2045) with high proportions of wind power. Two scenarios SWE_2045 & NFF_2045 were formulated to represent two distinct energy systems of the future. The SWE_2045 energy system still relies on fossil fuels, but to a lower extent compared to 2019 level and has increased levels of electrification and biofuels in the transport and industrial sectors. In comparison, the fossil fuels are completely removed in NFF_2045 and the industrial sector has significant demand for electrolytic hydrogen. Both the scenarios were simulated using EnergyPLAN, a deterministic energy system model, under each storage technology.

The results indicate that HPs coupled with TES has the potential to increase wind integration from 29.12% to 31.8% in SWE_2045 and 26.78% to 29.17% in NFF_2045. HP & TES also reduces heat production from boilers by 67% to 72% depending on the scenario, leading to overall reduction in total fuel and annual costs by at least 2.5% and 0.5% respectively. However, for wind integration of 31.1% in SWE_2045 the annual cost increases by 5.1% with hydrogen storage compared to TES. However, hydrogen storage shows better performance in NFF_2045, wherein the wind integration increases from 26.78% to 29.3%. Furthermore, increasing hydrogen storage for a lower wind capacity (60 GW) in NFF_2045 reduces both electricity import and export while simultaneously increasing the contribution of storage in fulfilling the hydrogen demand from 1.62% to 6.2%. Compared to TES and HS, the contribution of battery storage is minimal in sector integration. For increase in wind integration of 28% to 29%, the annual cost of a system with battery storage is 1.3% to 2% higher than that of the system with TES and hydrogen storage respectively. Therefore, HPs coupled with TES can improve flexibility in both scenarios. Hydrogen storage is not a promising option if the end goal is only to store excess electricity, as shown by the results in SWE_2045. However, it demonstrates better utilization in terms of wind integration, reduction in electricity import and export when there is a considerable demand for hydrogen, as in the case of NFF_2045.

Keywords: VRES, Energy System Model, CEEP, Wind integration, Thermal Energy Storage, Hydrogen Storage, Heat Pumps, Electrolysers

Sammanfattning

Sverige ligger i framkant när det gäller avkarbonisering och har mål att nå nettonollutsläpp till 2045. Även om elsektorn är nästan fossilfri, är industri och transport fortfarande beroende av fossila bränslen. Ambitiösa initiativ som Hydrogen Breakthrough Ironmaking Technology (HYBRIT), tillväxt av elbilsmarknaden och expansion av vindkraft syftar till att påskynda utsläppsminskningar. Dekarbonisering av transport, industri och storskalig vind- och solcellsintegrering i framtiden kräver att man studerar Sveriges energisystem i nationell skala i samband med sektorskoppling, extern transmissions- och lagringsteknik.

Därför syftar denna studie till att bestämma effekten av termisk energilagring, vätelagring och batterier via Power-to-heat & Power-to-hydrogen-strategier i det framtida svenska energisystemet (2045) med höga andelar vindkraft. Två scenarier SWE_2045 & NFF_2045 formulerades för att representera två distinkta framtidens energisystem. Energisystemet SWE_2045 är fortfarande beroende av fossila bränslen, men i lägre utsträckning jämfört med 2019 års nivå och har ökat nivåerna av elektrifiering och biobränslen inom transport- och industrisektorn. Som jämförelse är de fossila bränslena helt borttagna i NFF_2045-scenariot där transportsektorn endast är beroende av el och biobränslen, medan industrisektorn har en betydande efterfrågan på elektrolytiskt väte. Båda energisystemen simulerades med EnergyPLAN, en deterministisk energisystemmodell, för olika testfall under varje lagringsteknik. Resultatet av simuleringen bedömdes i termer av kritisk överskottselproduktion, potential för ytterligare vindintegration, total bränslebalans i systemet och årliga kostnader.

Resultaten indikerar att värmepumpar i kombination med termisk energilagring kan förbättra flexibiliteten i båda scenarierna genom att minska den kritiska överskottselproduktionen och bränsleförbrukningen samtidigt som vindintegrationen förbättras. Vätgaslagring är inget lovande alternativ om målet är att endast lagra överskottsel, vilket framgår av vindintegrationsnivåerna i SWE_2045. Det förbättrar dock vindintegration och tillförlitlighet avsevärt när det finns en betydande efterfrågan på vätgas i NFF_2045. Som jämförelse är batteriernas bidrag till vindintegration minimalt i båda scenarierna i samband med sektorintegration på grund av utnyttjandet av överskottsel av värmepumpar och extern överföring av restel. Valet av lagringsteknik i framtiden beror dock på dess tekniska ekonomiska utveckling och energipolitik.

Nyckelord: VRES, Energisystemmodell, CEEP, Vindintegration, Värmeenergilagring, Vätgaslagring, Värmepumpar, Elektrolysörer

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List of Abbreviations

GHG	Greenhouse Gas
VRES	Variable Renewable Energy Sources
RES	Renewable Energy Sources
PHS	Pumped Hydro Storage
HYBRIT	HYdrogen BReakthrough Ironmaking Technology
ESM	Energy System Model
SES	Smart Energy Systems
EV	Electric Vehicles
PV	Photo Voltaic
TES	Thermal Energy Storage
CAES	Compressed Air Energy Storage
AWE	Alkaline Water Electrolyser
BESS	Battery Energy Storage System
LCOE	Levelized Cost of Electricity
PtH	Power to Heat
PtH_2	Power to Hydrogen
V2G	Vehicle to Grid
CEEP	Critical Excess Electricity Production
DH	District Heating
CHP	Combined Heat and Power
HP	Heat Pumps
CCS	Carbon Capture and Storage
HS	Hydrogen Storage
IH	Individual Heating
ETL	External Transmission Capacity
HD	Heat Demand
H&ED	Heat & Electricity Demand

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1. Introduction

Since the pre-industrial era, consumption of fossil fuels has played a major role in the increase of Greenhouse gas (GHG) emissions. These emissions mainly due to anthropogenic activities have contributed towards global warming, rise in sea levels & climate change. Multitudinous risks associated with the climate change are projected to increase with the rise in global temperature. [1]. The primary objective of the Paris agreement is to restrict global warming to less than 2^{o}C compared to the pre-industrial levels. Therefore, it emphasizes on technological advancement to reduce GHG emissions & tackle climate change. [2].

GHG emissions from the energy sector was 34.2 Gt CO_2-eq in 2019. The Covid-19 pandemic in 2020 caused a decrease in energy demand leading to a reduction in emissions by 5.8% [3]. However, the economic recovery in 2021 induced an increase in the energy demand leading to GHG emissions of 40.8 Gt CO_2-eq [4]. Energy sector encompassing power generation, transport & industries is one of the key contributors to GHG emissions. Within the energy sector, production of electricity & heat accounts for largest share of emissions followed by the industry & transport. [5].

At global level, the total energy supply in 2019 was 606 EJ. Fossil fuels such as coal, oil and natural gas constituted around 80.9% of this supply. The contribution of hydropower was 2.5% & the combined contribution of solar & wind energy was less than 2.2%. Around 63.1% of global electricity (26,936 TWh) was supplied by fossil fuels, while the combined contribution of hydroelectricity, biofuels, waste & other variable renewable energy sources to this mix was around 26.5%. [6].

In this regard, decarbonisation of energy sector plays a paramount role in hindering global GHG emissions. The goal of limiting global temperature rise to 1.5^{o}C requires extensive technological advancement in multiple avenues. Increasing electricity production from renewable sources such as solar & wind, energy conservation, improving energy efficiency, electrification of transport & heat sectors and production of fossil-free hydrogen are some of the key solutions. [7]. Decarbonisation of power generation coupled with electrification of transport; industry & other end-use sectors is a vital element in energy transition. However, integration of VRES such as solar or wind energy requires a flexible electricity grid to ensure reliability and security of supply. [8].

Large-scale integration of VRES is a challenging task due to the mismatch in electricity demand & supply. One of the potential issues is the curtailment that can reduce the value addition and cost-competitiveness of renewable sources. [9]. For instance, around 250 TWh of electricity generated by VRES was curtailed annually in recent years, which is close to the annual electricity demand of Spain. Storage of this electricity would have prevented 180 Mt CO_2 which is almost 3% of total GHG emissions of the US in 2018. [10]. Therefore, deployment of different storage technologies is an important factor in reducing the curtailment & improving the flexibility of the grid. [9].

Energy storage domain encompasses a broad spectrum of technologies based on energy carrier, storage medium, cycle duration and so on [11]. Pumped Hydro-Storage (PHS) is the most widely used storage technology with a global capacity of 8500 GWh. It constituted 90% of the total electricity storage in 2020. [12]. Nevertheless, in recent years, grid-scale & behind-the-meter battery storage is gaining momentum due to reduction in costs. Grid-scale storage is anticipated to provide both short-term (balancing and ancillary services) and longer-term storage in the decarbonized energy systems of the future (2050). [12]. However, instead of focusing only on electricity storage that offers limited flexibility options, exploiting the advantages of sector coupling & other forms of storage such as Thermal Energy Storage (TES) can unlock better avenues. [13]. Further, the need for large-scale & seasonal storage in the future VRES systems has sparked renewed interest in hydrogen as an alternative energy carrier. [8].

The European Union has discerned energy storage as an important dimension in enhancing the flexibility & reliability of the RES based future energy systems. It has framed policies, research and development initiatives to facilitate energy storage. The pertinent regulations are embedded in various regulatory acts, but the implementation is specific to each member country. [14]. Currently, PHS is the most prominent type of storage in Europe. Nonetheless, batteries are witnessing increased deployment & other storage technologies like green hydrogen are under consideration as possible alternatives for the future. [15].

Sweden is at the forefront of decarbonization and has goals to reduce GHG emissions by 59% in 2030 compared to the levels in 2005, and to reach net-zero emissions by 2045 [16]. Since 1984, the country's annual energy supply has remained within the range of 500 to 600 TWh. In 2019, the total energy supplied to the Swedish energy system was around 548 TWh. [17]. Figure 1 shows the electricity supply mix of Sweden in 2019.

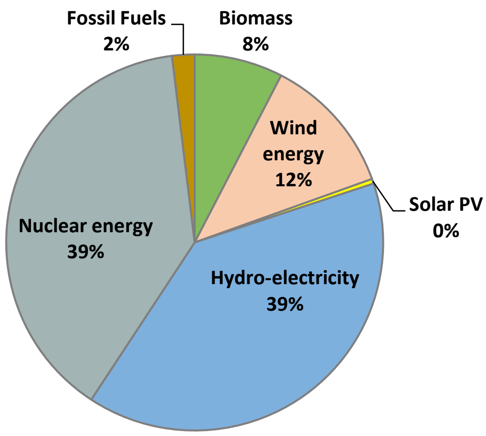


Figure 1: Composition of different energy sources in the Swedish electricity supply mix of 2019 [17], [18]

Fossil fuels constituted around 26.4% of the total energy supply in 2019. Electrification was lowest in the transport sector. The contribution of fossil fuels was significant in industry & transport sectors. Iron & Steel industry extensively used coal, coke, oil & natural gas, while the pulp & paper industry mainly relied on biofuels & electricity. 75% of energy in the transport sector was supplied by gasoline & diesel [18]. The share of biomass in the total supply mix has steadily increased in the last 20 years. Wind & Solar PV have also risen to prominence in the last decade [17].

Sweden's national energy and climate plan outlines the emission target for long-term. The goal is to reduce the net emissions of GHG to zero by 2045 and thereafter achieve negative emissions. This translates to reduction of emissions by 85% compared to the levels in 1990. The government launched 'Fossil-Free Sweden' in 2016 to start dialogue between stakeholders from different sectors. The target for 2040 is to have 100% renewable energy-based electricity production. However, there is no specific deadline or roadmap pertaining to the future of nuclear energy. With initiatives such as electrification of transport sector & HYBRIT (HYdrogen BReakthrough Ironmaking Technology) in the horizon, augmentation of wind power is required to facilitate energy transition. An electricity grid with high proportions of wind & solar PV must be flexible to ensure reliability. Thus, the plan elucidates the importance of establishing demand response, energy storage & balancing capacities.[19].

Energy transition is an enormous challenge. The policy makers require clear-sighted advice to make informed decisions. Thus, Energy System Models (ESM) serve as guiding instruments and offer insights into current & future energy systems. [20]. Decarbonization strategies at the national level require notable changes to the energy infrastructure [21]. Therefore, the interaction between different sectors & energy carriers is considered as a crucial element in the energy systems of the future [22]. Thus, an ESM applied at the national level must accommodate climate goals, different sectors and their interconnection in the model [21].

In this context, it is imperative to study the role of storage technologies in the future energy system of Sweden (2045) with high proportions of VRES and increased electrification in transport & industrial sectors. Therefore, the primary objective of this thesis is to ascertain the impact of hydrogen storage, thermal energy storage & batteries on VRES integration at national level. In this regard, two scenarios: SWE_2045 & NFF_2045 were formulated to study different combinations of demand and energy supply mix. EnergyPLAN model was used, as it facilitates Smart Energy Systems (SES) approach and simulation of energy systems at national level with an hourly resolution including electricity, heating, transport & industrial sectors.

Chapter 2 focuses on the review of recent studies pertaining to RES based future energy systems in the literature.

2. Literature Review

Technical and economic analysis of RES integration is a vital element in planning the energy transition. Therefore, modelling of energy systems plays a crucial role in understanding the impact of RES integration on different sectors. Energy system models can be tailored to address various research questions containing a broad spectrum of objectives & constraints. The scope of the energy systems also varies in terms of geographical boundaries such as regional, national or global levels. [23].

Increased deployment of VRES enables access to clean energy and negates many disadvantages of fossil-fuel based power plants. However, their intermittency leads to significant mismatch in electricity demand & supply. Higher the integration of VRES, higher is the production of excess electricity during certain hours in a day that must be curtailed via a 'dump load' [24]. Katsaprakakis et al. & Ma et al. conducted feasibility studies to propose VRES based power systems for remote islands in Greece & Hong Kong respectively, wherein the estimated excess electricity was around 48% of total production [25], [26]. In a study pertaining to a German power system with a high share of VRES, Kies et al. illustrated that significant curtailment reduced the capacity factor by 60% to 70%, eroding the competitiveness of renewable energy systems [27]. Frew et al. analysed measures to improve operational flexibility of VRES Systems in terms of costs & benefits. The study considered an enhancement of transmission network, overgeneration of RES, storage & flexible load via EV charging as solutions to mitigate the uncertainties.[28]. Huber et al. provided an assessment of flexibility in the context of integration of solar PV and wind power in Europe. The study concluded that VRES share of more than 30% in the supply mix would require flexibility mechanisms such as demand-side response & storage [29].

Energy storage can bridge the gap between demand & supply caused by the intermittent nature of VRES [11]. Luo et al. reviewed characteristics of different storage technologies such as Pumped-Hydro Storage (PHS), battery, hydrogen storage, Thermal Energy Storage (TES), CAES, Flywheel etc. Key takeaways from this study are: worldwide deployment of PHS plants is due to its technological maturity; Li-ion batteries have relatively high energy density & thus, have undergone wide range of development in small-scale systems; seasonal storage has not yet evolved on a commercial scale due to problems such as self-discharge & constraints in storage capacity. [11].

For example, Shams et al. proposed a two-stage stochastic model to minimize the curtailment of excess electricity produced by VRES in California, USA. The analysis considered Alkaline Water Electrolyser (AWE) based hydrogen & BESS as storage mechanisms to determine optimal planning in three scenarios. [30]. McPherson and Karney developed a scenario based 'production cost dispatch' model, SILVER (Strategic Integration of Large-scale Variable Energy Sources) to study the role of demand response, storage (PHS), EVs (Li-ion batteries) & expansion of transmission in high share of VRES scenarios for Ontario, Canada. This analysis addressed two aspects – variation in utilization of storage, EVs and demand response with respect to increasing share of VRES; capital costs, operational costs & GHG emissions in each scenario. [31]. Chen et al. analysed the performance of 100% RES based energy systems comprising of Solar PV, Wind & biomass, for cities containing low-density communities in China. Batteries and Thermal Energy Storage (TES) were considered in this model, as the study focused mainly on electricity & heating loads. [32].

Studies pertaining to 100% RES energy systems of the future have evolved into a new realm of research, especially in Europe, USA & Australia. Models at national level have been more common compared to regional or global level. Besides, many of these publications primarily focus on electricity sector. However, studies in the recent years have embraced 'cross-sector' approach. Although some papers have investigated the transition pathways required to reach the state of '100% RES', in many cases, the analysis focuses on understanding the dynamics of different technologies in these systems. [33].

Research by Becker et al., focused on energy system modelling at national level to identify the optimal mix of solar PV and Wind for a 100% RES electricity system in the USA with the objective to minimize LCOE, balancing and storage requirements [34]. Elberry, Thakur and Veysey studied the impact of long-term geological hydrogen storage on the Finnish electricity system. Results showed that addition of storage system in the model reduced the share of fossil fuels in the supply mix. [35]. Abid et al.,presented technical & economic feasibility analysis for Burkina Faso. The study considered integration of solar PV, PHS & batteries in the model to address low electrification in the region. Results showed that batteries were an expensive form of storage compared to PHS due to relatively higher capital costs & lower life span. [36]. Zhong et al., studied the current status of electricity sector of Sweden to examine the possibility of replacing nuclear & conventional thermal power plants with wind power. The results showed that this replacement is possible by increasing the capacity of wind power by three times the current levels. The study also relied on PHS as a storage mechanism to facilitate this integration. [37].

Schoenfisch and Dasgupta argue that electricity sector only approach will lead to an energy system with high costs of storage and inefficient flexibility mechanisms [13]. For instance, the industrial sector constituted 38% (156 EJ) of global energy consumption in 2020. Around 68% of this demand was supplied by fossil fuels and 22% by electricity [38]. Therefore, coupling industry electrification & large-scale integration of VRES has the potential to improve flexibility of the energy system, reduce the direct use of fossil fuels in industry and lower the cost per kWh [39]. Sorknaes et al., assessed the impact of industrial electrification on the 100% RES energy system of Denmark for 2050. The study concluded that electrification of industrial heat process is more favourable than switching to hydrogen as fuel, due to lower cost & higher efficiency in case of electrification. [40]. Yuan et al., examined the role of electrification of transport in energy transition for Beijing-Tianjin-Hebei region in China. The results of this study showed that the transport sector containing 100% EVs can be coupled with RES energy system without the need for additional integration of VRES in 2050. [41].

Therefore, in the context of 100% RES based energy system of the future, the concept of 'Smart Energy Systems' (SES) is presented by Lund et al. [13]. It provides a holistic view of energy system with cross-sector approach to develop synergies between different sectors. Such an interconnected system creates new avenues to improve flexibility. [13].

Additionally, in the last decade, Power-to-X (PtX) concept has gained momentum in the modelling of future RES energy systems. It signifies the conversion of electricity produced by RES into X, wherein X can be a gas like hydrogen or heat or a liquid. In PtH_2, hydrogen is produced by electrolysis of water. The hydrogen then stored can be utilized for various applications including production of methane or electricity via fuel cells. [42]. In case of Power-to-heat (PtH), electricity is converted to heat via a heat pump or electric boilers. PtH can be coupled with TES to develop synergy between power & heat sectors. [43].

In another study, two future energy systems were modelled, one with SES approach and another with traditional approach (without sector coupling), for Zagreb, Croatia. Results showed that the consumption of biomass in traditional approach model was much higher than in SES model. Further, SES model showed better utilization of VRES electricity. However, overall cost in SES model was slightly higher than the traditional model. [44].

Meha et al., and Al-Ghussain et al., developed future RES energy systems for Kosovo, which relies heavily on coal. The systems were developed in EnergyPLAN modelling tool, which facilitates SES approach. Both studies showed that PtH coupled with TES in district heating offered a less expensive pathway for transition compared to electricity-only approach. [45], [46].

Osorio-Aravena et al., formulated 4 scenarios to identify energy transition pathways for Chile from 2015 to 2050. The models incorporated a high share of solar PV in the electricity mix & included transport, desalination and heat sectors. The study concluded that it is technically feasible to establish a sustainable energy system in Chile via Solar PV, interconnection of transmission lines & sector coupling. It also showed that with conducive energy policies, 100% RES systems can facilitate the country to attain carbon neutrality by 2030. [47]. In another research, a 100% RES system with sector coupling of transport, industry, power & heat was configured for Kazakhstan in 2050. The model consisted high share of solar PV in the supply mix. The storage technologies included batteries & hydrogen for PtX. The study showed that the synergy between sectors & long term storge can improve flexibility, reduce LCOE & significantly lower GHG emissions. [48].

In a study pertaining to 100% RES system, a transition pathway was developed Germany upto 2050. The scenarios incorporated sector coupling via increased electrification of transport & industrial sectors, wherein part of the energy demand in the industry was fulfilled by biomass. The model relies primarily on batteries (V2G) & hydrogen storage technologies. The results showed that EVs, electrolysers & heat pumps improved the flexibility of the system & facilitated additional integration of VRES. [49]. Child and Breyer developed a 100% RES scenario for the energy system of Finland in 2050. The model incorporated battery, V2G, TES & grid gas storage to understand their role in the energy mix. Results showed that V2G had a greater role than batteries in electricity storage; Power-to-Gas (PtG) contributed towards balancing demand & supply during intermittent periods of VRES generation. However, the study did not explore the role of pumped hydro storage in this model. [50].

Tang et al., investigated the feasibility of hydrogen production in the context of increasing VRES installations, profitability of nuclear power plants in the future, fluctuating electricity prices and the Swedish energy policies. The analysis showed that low electricity prices due to increased production from VRES sources could pave way for production of hydrogen in nuclear power plants. [51].

Schweiger et al., studied incorporation of PtH in district heating in Sweden. The analysis showed that excess electricity production from solar PV & Wind can be utilized in district heating via heat pumps coupled with TES. The estimated potential was in the range of 0.2 to 8.6 TWh for different cases. However, the study did not consider the import or export of electricity. [52].

EnergyPLAN primarily serves the purpose of energy system analysis at national scale. The model has been used to study various dimensions of energy transition to 100% RES systems of the future. In many cases, the target year considered is between 2040 to 2050. For instance, this type of analysis has been conducted for countries such as Germany, Norway, Denmark, Ireland, Chile, China, Jordan, Singapore, Portugal, Hungary and Romania. [53], [54]. Ahmed and Nguyen presented distinct future energy systems for Växjö municipality in Sweden using EnergyPLAN model in the context of carbon neutrality in both short & long-term transitions. [55].

Apart from formulating strategies, due to its versatile nature, EnergyPLAN model has been used to explore the role of certain technologies in the ESM landscape. Some examples are: the role of Compressed Air Energy Storage (CAES); hydropower of Norway; role of biomass & biogas; role of district heating & heat pumps; role of V2G in the energy system; flexible electricity demands; electricity markets & energy efficiency technologies. [54].

In essence, 100% RES Energy system at national level with SES approach has been incorporated in many research publications. In case of the Swedish energy system, the ambiguity regarding the future of nuclear power plants, anticipated increase in wind & solar PV installations, change in energy demand across various sectors and the future of hydrogen in steel industry are some of the uncertain dimensions. [56],[57],[17],[19].

Therefore, this thesis aims to address these uncertainties via Smart Energy Systems approach. The goal is to envisage RES based energy system in Sweden in 2045 and to understand the impact of storage technologies on VRES integration & overall energy mix.

3. Research Objective

The objective of this thesis is to determine the role of hydrogen storage, thermal energy storage & batteries in the future energy system of Sweden driven by large scale integration of VRES in 2045 in the context of sector integration. This approach encapsulates electricity, district heating, transport & industrial sectors at national scale. The key aspects considered are increased electrification of transport & industrial sectors, electricity supply mix primarily driven by wind energy, hydropower, nuclear energy & solar PV and enhanced hydrogen demand in the industrial sector.

Following research questions were formulated to fulfil this objective.

- What is the impact of following storage strategies on energy systems with varying demand & supply characteristics, in terms of utilizing excess electricity production, total fuel mix and system costs?
    - Power-to-heat with thermal energy storage
    - Power-to-hydrogen with hydrogen storage
    - Batteries
- What is the contribution of each storage technology to the additional integration of wind power into the energy system?

3.1 Scope and Limitations

1. The energy systems in the scenarios incorporated in EnergyPLAN are deterministic models and hence, the output of the simulation depends on the model inputs and . illustrates the characteristics of various systemic parameters under different test conditions.
2. The simulation of an energy system set in the future hinges on considerations in defining the future energy system and data referenced from various studies in the literature. Therefore, the scenarios are modelled at national level with aggregated inputs and hence, regional constraints pertaining to SE1, SE2, SE3 & SE4 are not taken into account. Thus, the output represents systemic behaviour for whole of Sweden.
3. Hourly distribution of demand and supply in electricity sector is constructed based on the current hourly behaviour Hourly heat demand was estimated in accordance with the heat degree days in 2045 based on the scenario developed by SMHI. Distribution files from the EnergyPLAN library were used for hourly distribution in transport and industrial sectors.
4. The hourly operation of storage in the energy systems is based on the aggregated & defined storage capacities, hourly balance of demand and supply and the choice of simulation strategy. Thus, the model does not consider technical constraints in each storage technology.

4. Background

This chapter encapsulates the context of this study, specifically, the current dimensions of the Swedish energy system, different storage technologies, an overview of ESMs and EnergyPLAN model.

4.1 Energy System of Sweden

Since 1984, the annual energy supply of Sweden has remained within the range of 500 TWh to 600 TWh. In 2019, the total energy supplied was approximately **548 TWh**. [17], [18]. Figure 2 shows the energy balance at national level.

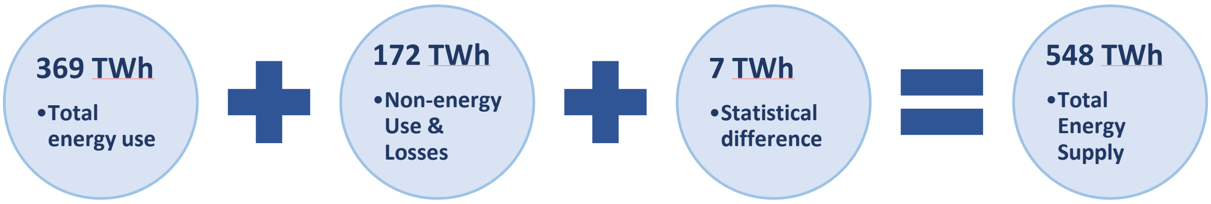


Figure 2: Energy balance of the Swedish energy system in 2019[1] [17], [18]

Sweden has an eclectic mix of energy sources. Hydropower, wind, biomass & to a small extent, solar PV are domestic sources. Fossil fuels such as oil & natural gas, nuclear fuels & a part of biofuels are imported from other countries. [18]. Figure 3 shows the composition of different energy sources in the supply mix.

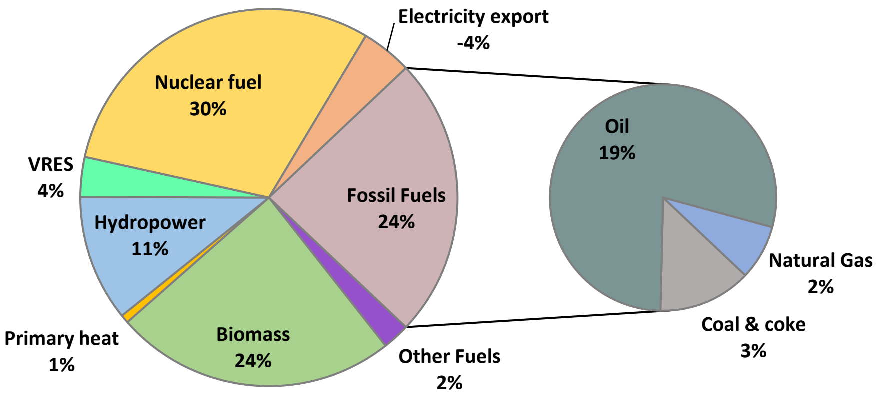


Figure 3: Share of various energy sources in the Swedish supply mix of in 2019. Primary heat is the heat supplied by large heat pumps. Other fuels represent energy from waste [17], [18]

As shown in figure 3, around 41% of the total energy was supplied by RES. Nuclear fuel, biomass & hydropower constituted a major share of the primary energy supply. Nuclear fuel

[1] Energy supplied towards International maritime & aviation transports are excluded in this analysis

depicts the gross nuclear fuel input energy of 181 TWh. The electricity production after conversion losses was 64.3 TWh. VRES mainly comprised of wind energy (19.846 TWh) and a relatively very small amount of solar PV (0.67 TWh). The consumption of fossil fuels was mainly observed in the transport & industrial sectors. Total fossil fuels supplied to the Swedish energy system was 323 TWh, out of which 143 TWh passed through the refineries and were exported to other countries; 35 TWh was supplied towards international maritime & aviation transport; and the remaining 144 TWh shown in figure 3 was utilized within Sweden. [17], [18].

A part of fuel input amounting to 172 TWh comprised of (1) energy conversion and transmission losses and (2) energy required to operate various installations producing electricity, District Heating (DH) & refineries. Thus, the final energy consumption was 369 TWh. Residential & Services, Transport & Industrial sectors used 144 TWh (39%), 83 TWh (22.5%) and 142 TWh (38.5%) respectively. [17], [18]. Figure 4 shows the composition of different energy carriers in the final energy consumption.

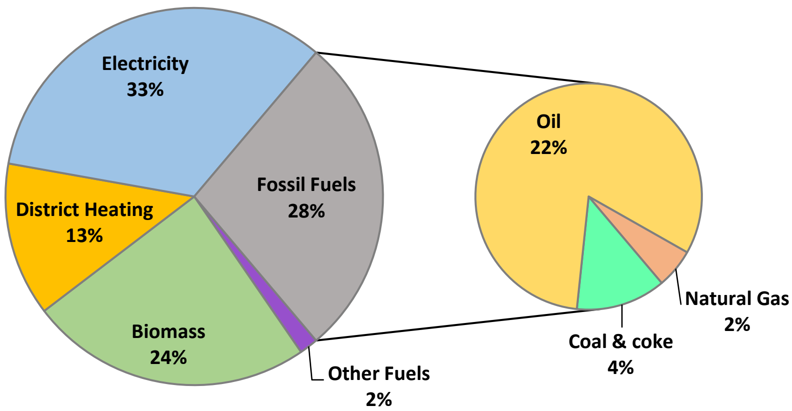


Figure 4: Final energy consumption (369 TWh) of different energy carriers in 2019. Other fuels represent energy from waste [17], [18]

As shown in figure 4, 28% of the final energy use was fulfilled by fossil fuels. Contribution of oil or petroleum products was the largest among fossil fuels due to its substantial use in the transport sector. However, the use of biofuels in the transport sector is steadily growing in recent years. DH and industry relied on biomass to a large extent, 64% & 41% respectively. Residential & Services sector accounted for the highest consumption of electricity and heat from DH. [18].

On the whole, fossil-free energy sources have a remarkable share in the primary energy supply mix of Sweden. However, transport & manufacturing industries still rely on fossil fuels to a significant extent. Thus, decarbonisation strategies for these sectors play an important role in reaching climate goals.

4.1.1 Electricity

Electricity is one of the principal energy carriers in Sweden. Nuclear and hydropower constitute a major part of generation followed by wind power & CHP plants. The share of solar PV is less than 1% in the current supply mix [17]. Figures 5 & 6 show electricity generation from different energy sources since 2000 & 2011 respectively.

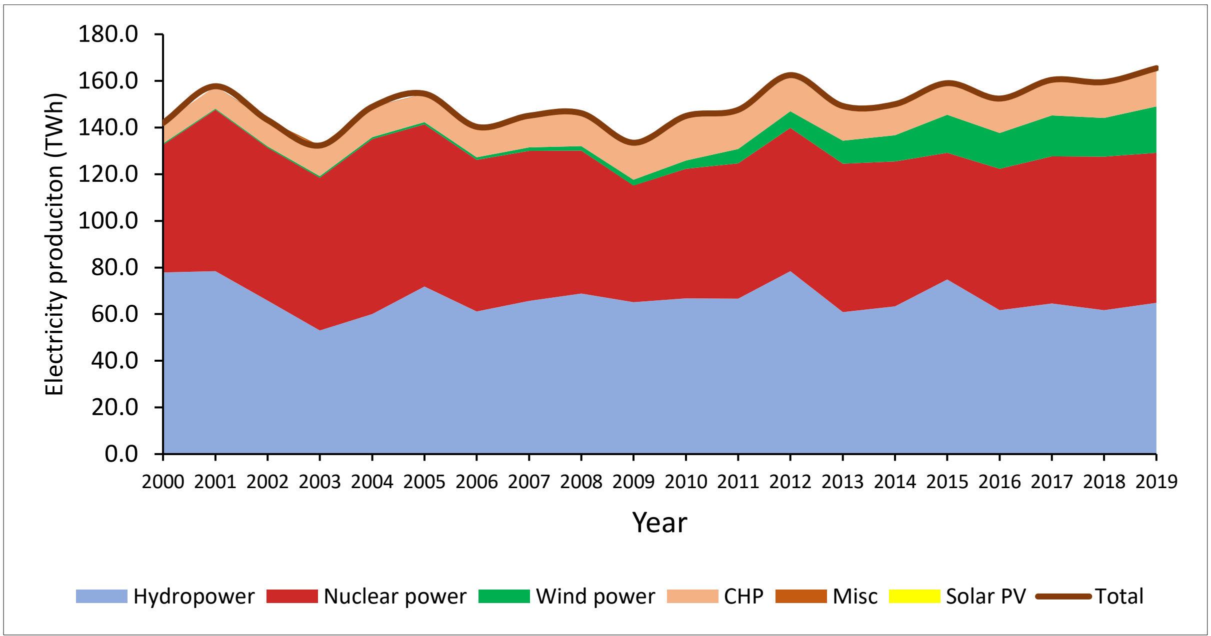


Figure 5: Net electricity production by different types of power plants since 2000. CHP Electricity includes production from both DH & industry. Misc. denotes production from TPPs other than CHP. [17], [18]

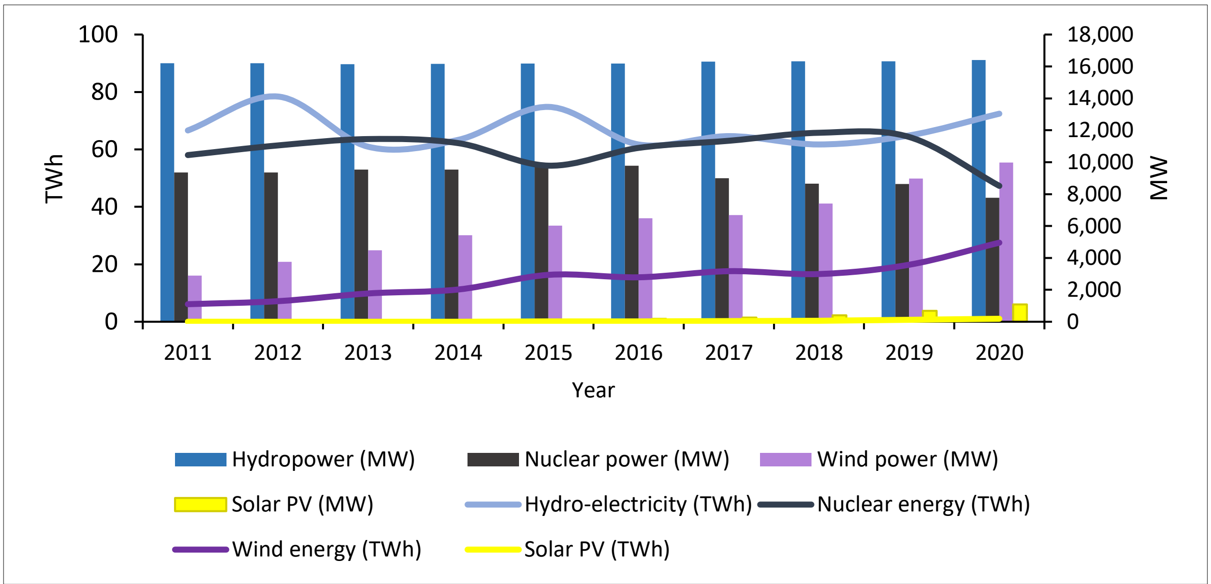


Figure 6: Installed capacities (MW) & generation (TWh) of four power generation technologies in Sweden from 2011 to 2020 [57], [17]

As presented in figures 5 & 6, hydropower & nuclear power plants have been the primary source of electricity generation, wherein the production has varied between 50 to 80 TWh. However, some nuclear reactors were closed in the last five years [58]. Wind power has shown tremendous growth since 2009. In comparison, production from CHP plants has undergone a steady increase. Although solar PV installations have increased remarkably in recent years, their contribution relative to other sources is very small. [57], [17]. Table 1 shows the installed capacities and generation in 2019. Figure 7 shows the corresponding electricity supply mix. Out of 165 TWh of net electricity production, 26 TWh was exported and around 139 TWh was used within Sweden [17], [18].

Table 1: Installed capacities & production from different power plants in 2019. CHP includes both DH & industry. Misc. denotes other conventional thermal power plants [57], [17], [59]

Type	Hydropower	Nuclear Power	Wind power	Solar PV	CHP & Misc.	Total
Installed Capacity (MW)	16,462	8,624	8,681	698	8,343	42,808
Net Generation (TWh)	64.86	64.3	19.8	0.66	15.7	165.5

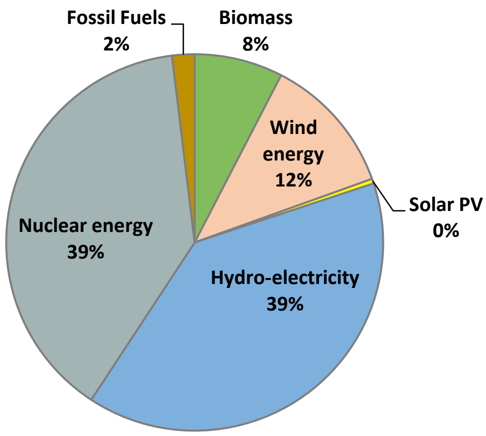


Figure 7: Composition of different energy sources in the Swedish electricity supply mix of 2019 [17], [18]

As illustrated in figure 7, hydropower and nuclear power each generated 39% of total electricity. VRES constituted 12.4% wherein 12% was from wind & only 0.4% from solar PV. CHP & other thermal power combined catered to the remaining fraction in which biomass accounted for 8%. Only 2% was from fossil fuels. In essence, around 98.4% of electricity produced in Sweden was fossil-free and 59.4% was from RES sources. [17], [18].

Sweden trades electricity with Denmark, Finland, Norway, Germany, Poland & Lithuania. The total international transmission capacity was 10,350 MW in 2019. It is expected to increase to 11,950 MW by 2030. [19]. From 2011 to 2019, Sweden produced net surplus electricity in the range of 7 to 27 TWh. [17]. In 2019, 35.23 TWh of electricity was exported while 9.07 TWh was imported, leading to a net export of 26.16 TWh [60].

Electricity as an energy carrier is utilized in all sectors. Since 2000, the demand has remained in the range of 130 TWh to 150 TWh. Residential & services sector has the highest demand (72 TWh), followed by the industry (48 TWh), DH & refineries (4.11 TWh) and transport (3 TWh). [17], [18]. However, electrification of transport, industry & additional usage of heat pumps in DH will alter the current combination of sectoral demands & also entail higher demand levels in the future [56].

Svenska kraftnät (SVK) – the Power System Operator & a state owned company in Sweden is responsible for maintaining electricity balance at all hours. SVK publishes hourly electricity data for each year. Figures 8 to 9 show hourly distributions of electricity produced by different types of power plants; electricity demand and import / export in 2019. The underlying data was downloaded from the company's website. [61], [62].

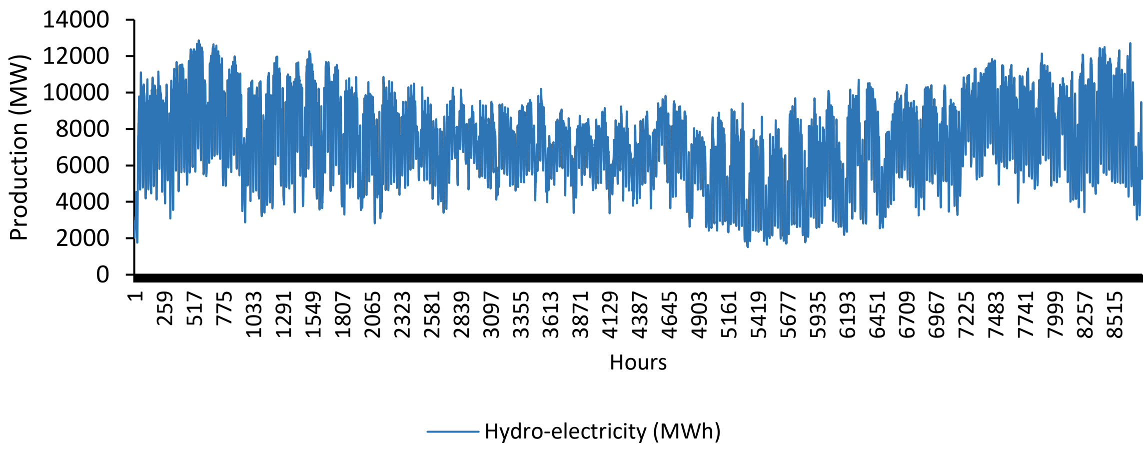


Figure 8: Hourly distribution of electricity produced by hydro power in 2019 [62]

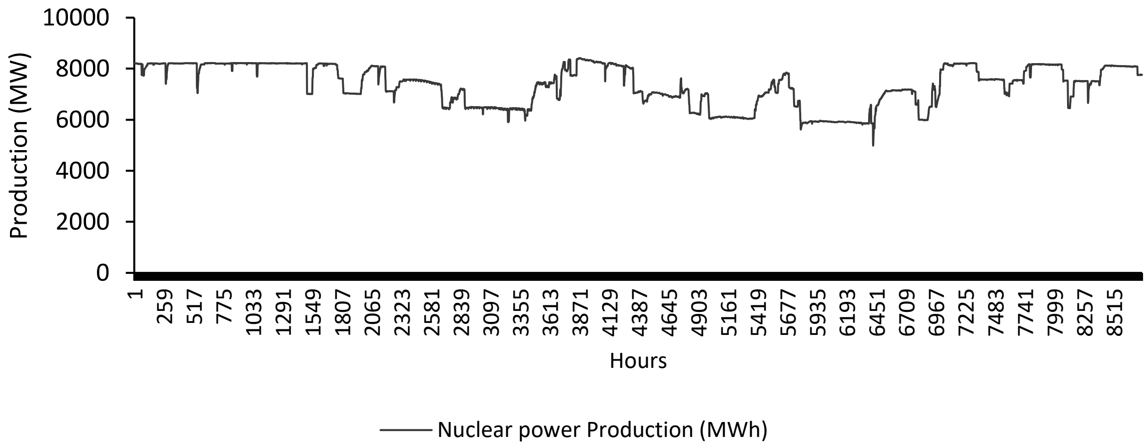


Figure 9: Hourly distribution of electricity produced by nuclear power in 2019 [62]

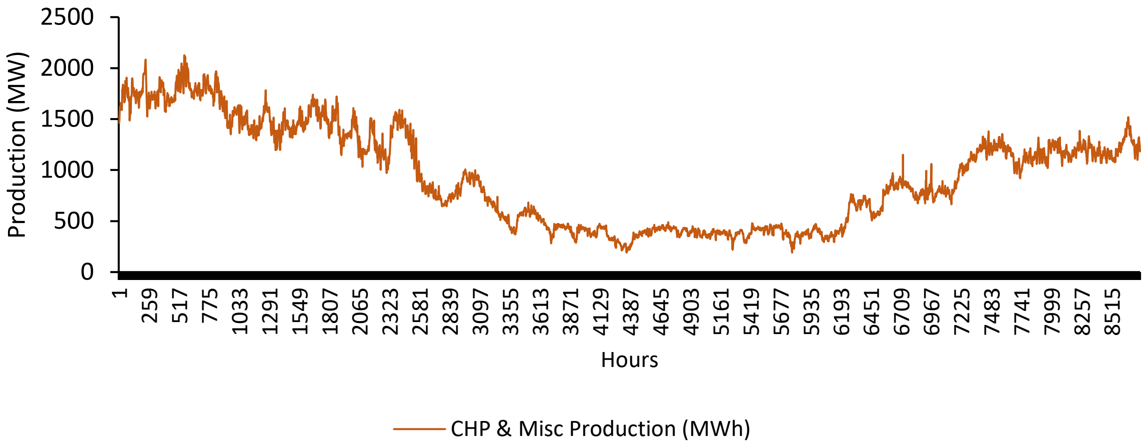


Figure 10: Hourly distribution of electricity by CHP & other thermal plants in 2019 [62]

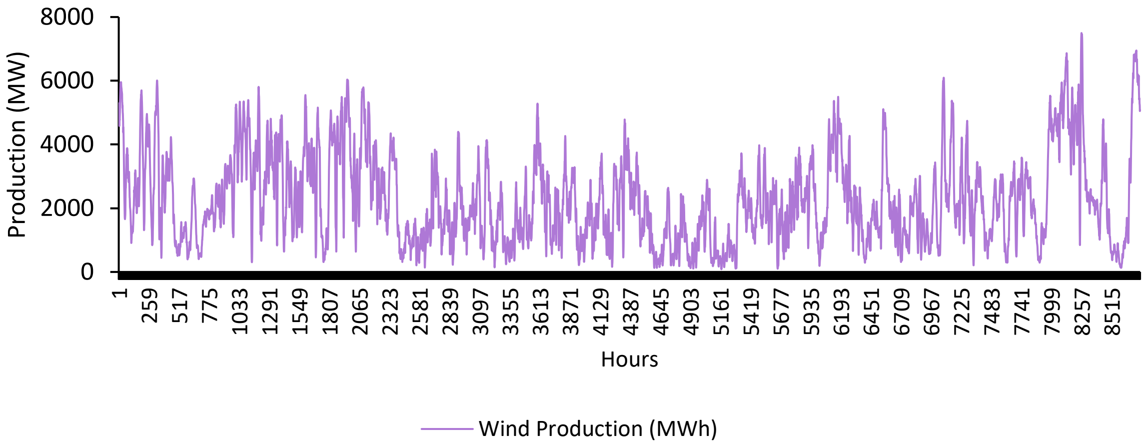


Figure 11: Hourly distribution of electricity produced by wind power in 2019 [62]

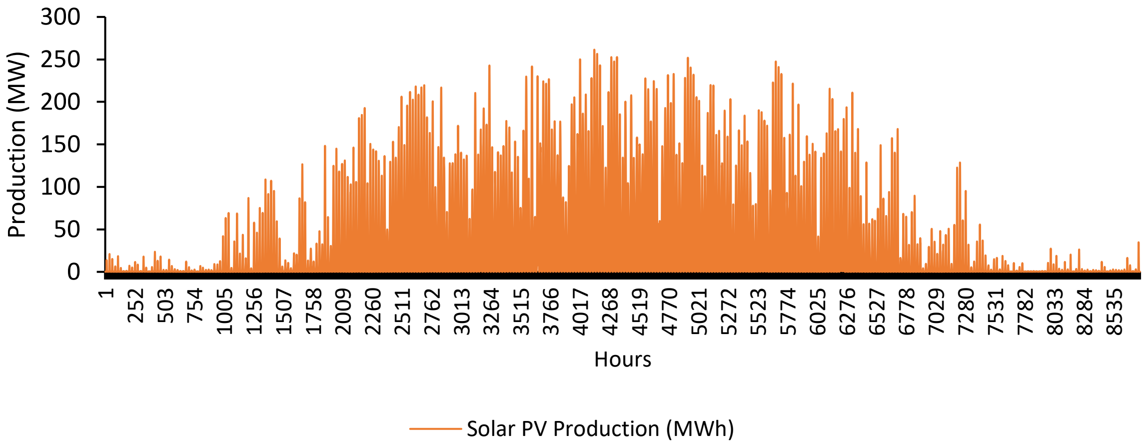


Figure 12: Hourly distribution of electricity produced by solar PV in 2019 [62]

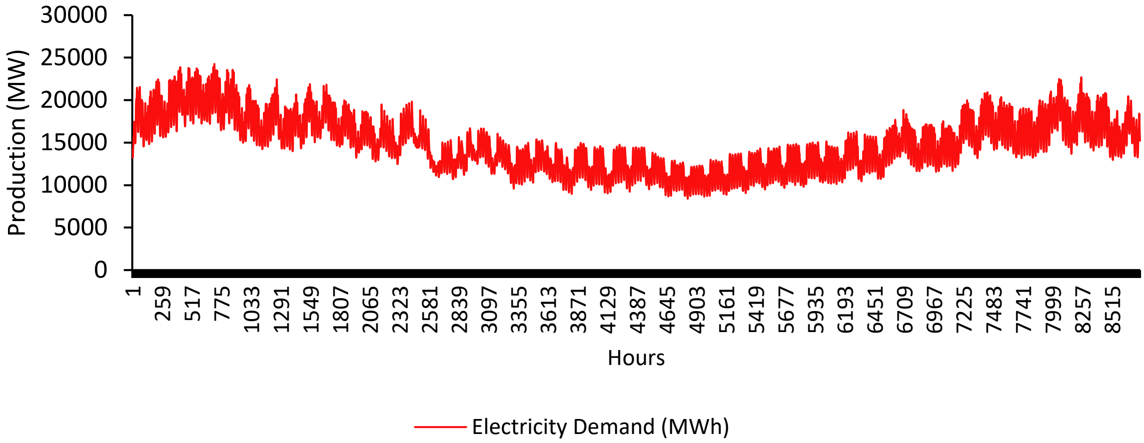


Figure 13: Hourly distribution of gross electricity demand in 2019 [62]

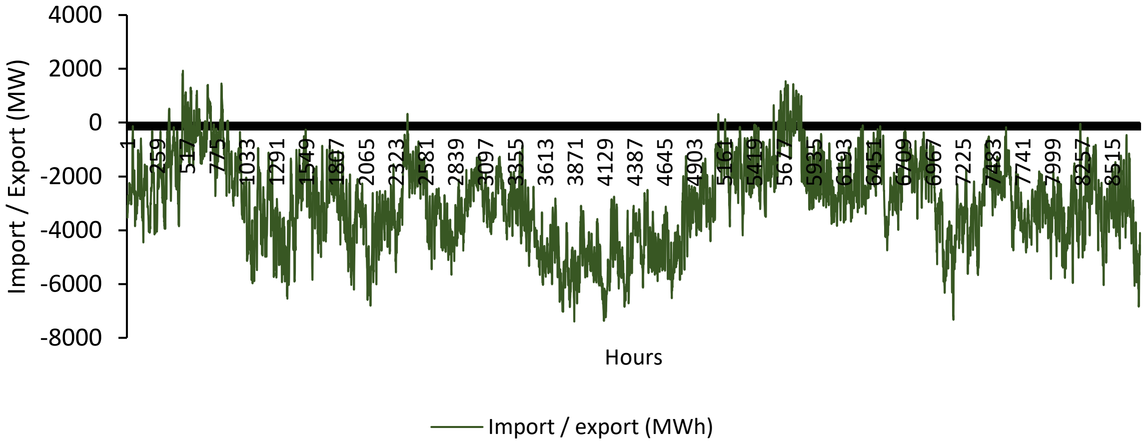


Figure 14: Hourly distribution of import / export of electricity in 2019. Import is denoted with positive (+) sign & export is denoted with negative (-) sign [62].

Following are the inferences drawn from the hourly distributions in figures 8 to 14:

- Hydropower has flexible generation profile throughout the year with higher levels of production in winter. The difference between maximum and minimum production is around 11000 MW.
- Production from nuclear power plants is high in winter & relatively low in summer and has a stable generation profile.
- Electricity from CHP is quite low in summer. In general, since CHP mainly caters to heat demand in DH, a reasonable exposition indicates that the operation of CHP is affected by different seasons.
- Wind power exhibits high levels of fluctuation throughout the year.
- Solar PV has high levels of production in summer and very low generation in winter, which can be attributed to irradiance, variations in daylight and seasonal effects.
- Electricity demand in winter is almost three times higher than the levels in summer.
- Export is quite high in summer. The number of import hours is much lower than the number of export hours.

Sweden has a liberalized electricity market. Electricity is traded via NordPool, a pan-European power market in the Nordic & Baltic region that facilitates buying & selling of electricity. It enables day ahead or spot market and intraday trading for 360 companies from 20 countries. It is jointly owned by Euronext (66%) and TSOs from different countries (34%) including SVK. [61], [63]. The NordPool market is divided into 15 geographical bidding areas [63]. Sweden is divided into four bidding areas as shown in figure 15. [61].

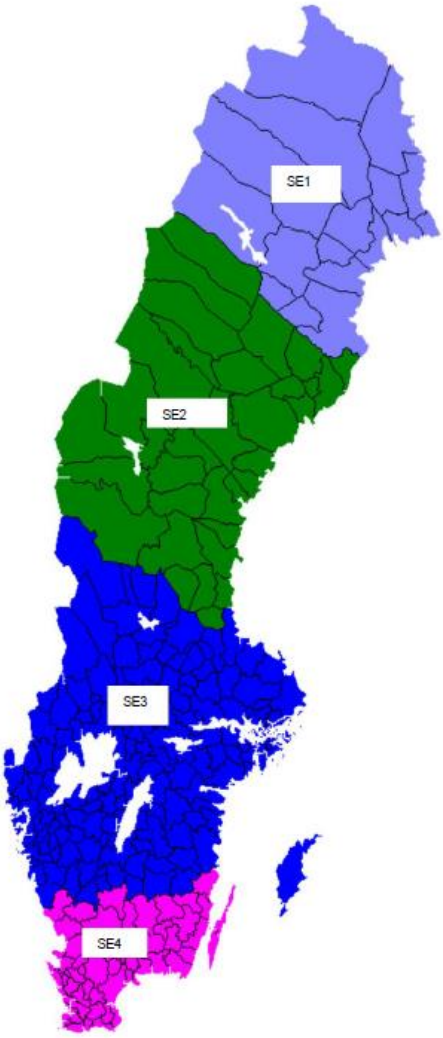


Figure 15: Four electricity bidding areas in Sweden [57].

The four bidding areas are: SE1 (Luleå), SE2 (Sundsvall), SE3 (Stockholm) & SE4 (Malmö). Constraints & limits to power transmission between different areas can lead to different prices. In general, prices are low when the supply is higher than demand & vice versa. Electricity price in a bidding area depends on the production & demand in that area. [61]. For instance, SE1 & SE2 produce excess electricity due to the high availability of wind & hydropower, whereas the demand is higher than the supply in SE3 & SE4, which has led to bottlenecks in transmission [19], [64]. Electricity prices are expected to increase in the future due to factors such as the increase in demand due to electrification of transport & industry, and rising prices of fuel & emission rights. However, it makes investments towards new VRES installations more attractive. [56]. Traditionally, the Transmission and Distribution (T&D)

network was built on centralized production of hydro & nuclear power to facilitate unidirectional flow from producer to consumer. However, increasing infusion of VRES electricity has imposed new challenges on the flexibility of the grid. The future system requires more flexibility to handle intermittent production. In addition, due to increasing solar PV installations in the residential sector & de-centralized generation, the grid should also support bidirectional flow, i.e., from consumers back to the grid. [18].

4.1.1.1 Wind energy

Wind energy is emerging as a rapidly growing source in the Swedish electricity system [18]. The share of wind power in the total supply increased from 1.8% in 2009 to 20.4% in 2022 [57], [17], [65]. From 2019 to 2020, the installed capacity increased approximately by 1 GW and the production by 7.7 TWh. At the end of 2021, the installed capacity was 12.06 GW. [66]. The largest wind farm is located near Blaiken nature reserve in the northern part. It has an installed capacity of 245.5 MW. Upon completion of project phase 1, Markbygden wind farm will be the largest installation in the country with a capacity of 644 MW. [67]. As of 2020, the country had 4,286 wind turbines [57].

Wind power plants are preferred in the north and along the coast due to conducive weather conditions. Further, it is easy to obtain permission in the north, although the prices are lower compared to southern areas. [19]. Reduction in costs has made wind power competitive without subsidy and has propelled the expansion of wind power plants. In general, onshore plants are favoured over offshore plants as the costs related to offshore plants are substantially higher than their onshore counterparts [67]. However, the production costs of offshore plants have shown a downward trend in recent years. This has led to the initiation of several offshore wind projects with a total capacity of 9000 MW in SE3 & SE4. [66].

The future of energy transition hinges on large scale integration of wind power in Sweden [56], [19]. Study conducted by the Swedish Wind energy association rendered that at least 90 TWh of production from wind power would be required to reach the goal of 100% RES electricity by 2040. To reach this level, the installed capacity must be doubled and the corresponding investment costs would be EUR 18.4 billion. [68].

Long-term scenarios developed by the Swedish energy agency shows that the production from wind power will vary between 64 TWh and 156 TWh in 2050, depending on the scenario. [56]. In this regard, the government has initiated a wind power plan to develop strategies for large-scale integration. The national climate plan emphasizes the need for measures such as demand response & energy storage required to address the challenges in flexibility. [19]. However, issues such as complicated permit process, limitations in connecting wind power plants to the grid, and conflict of interest with other governmental agencies must be addressed to ensure seamless expansion of wind power. [68].

4.1.1.2 Hydropower

The first hydroelectric plant was constructed in 1882 in Sweden [69]. Since then, hydropower has been a significant source of electricity in the supply mix. It caters to base load and also offers ancillary services such as balancing & frequency control. 80% of hydro-electricity is generated in the northern part of Sweden. Harsprånget is the largest power plant with an installed capacity of 977 MW, built on Lule river in the north. [70]. Since 1996, the total installed capacity has remained within the range of 16200 to 16400 MW. In this period, the production has varied between 50 to 80 TWh. A major part of RES electricity in Sweden (59.4%) is mainly due to hydropower (39%). [17], [18]. As of 2019, Sweden had around 600 dams & 1800 hydro-electric plants. Approximately 93% of hydro-electricity (65 TWh) was generated by 203 power plants, each rated above 10 MW. [69].

Hydropower is expected to play a crucial role in the energy transition in future. The government has initiated a national plan in order to review hydropower in the context of 100% RES based future energy system, considering revised environmental standards, and impact on local ecology & fisheries. [19]. Further environmental restrictions can potentially reduce the flexibility & financial incentives of hydropower plants [71]. Research conducted by the Swedish energy agency concludes that the production from hydro-electric plants in 2050 will remain at current levels. This inference is based on the reasoning that a marginal increase in production caused by additional water inflow due to climate change is negated by more stringent environmental policies in the future. [56].

4.1.1.3 Nuclear Energy

Since mid-1970s, Nuclear energy has been an essential part of the Swedish power system [17]. Nuclear power plants generated 64.3 TWh, 47.3 TWh and 50.5 TWh of electricity in 2019, 2020 & 2021 respectively. [57], [17], [72]. In 2021, it accounted for about 30% of the electricity supply mix compared to 39% in 2019 [17], [72]. Currently, three power plants containing a total of six reactors are in operation [58]. As of March 2022, installed capacity of nuclear power is 6885 MW. These reactors were connected to the grid in 1980s. They are owned by three companies – Vattenfall, Uniper SE and Fortum. These plants are located in the southern part of Sweden, at Forsmark – 3 Boiling Water Reactors, Oskarshamn – 1 Boiling Water Reactor and Ringhals – 2 Pressurized Water Reactors [59]. Two out of three reactors in Oskarshamn were closed in 2017 and two out of four reactors in Ringhals were closed in 2019 & 2020. [58].

The presence of nuclear energy in the supply mix of future energy system is still uncertain. In a Novus public opinion poll conducted in 2021, 46% of the respondents favoured building new nuclear plants; 31% favoured continued operation of existing plants; 14% opted for shutdown & 10% were undecided. [59]. Under the national energy & climate plan submitted to the EU parliament in 2020, the government mentioned that the target of 100% RES based electricity production by 2040 did not necessarily imply a complete shutdown of nuclear power [19].

Increased electrification in transport & industry and intermittent nature of VRES can endorse the extension of existing reactors or even propel the addition of new ones [56].

4.1.1.4 Solar PV

The contribution of solar PV to the electricity supply mix was only 0.4% in 2019. Nonetheless, the PV market has witnessed remarkable growth in the last 6 years. The number of grid-connected PV systems increased by 50% from 2019 to 2020. [18]. In the same timeframe, installed capacity elevated from 690 MW to 1090 MW [57], [18]. 500 MW was added in 2021, leading to a total capacity of 1.5 GW [73]. More than 80% of the current installations are in residential and commercial buildings. Centralized Solar PV parks constitute only 7% of grid connected PV systems. Majority of PV installations are located in SE3 & SE4. [64].

It can be attributed to the fact that the annual global mean irradiance primarily depends on the latitude. It is in the range of 900 to 1050 kWh/m^2 in southern areas such as Stockholm, Gothenburg, Visby etc. It is almost 25% lower in the northern regions such as Kiruna or Luleå. [74]. Since 2009, the government has provided financial support towards investment in Solar PV systems. The budget allocation for PV support has increased over the years. It was around SEK 835 million in 2020. [19]. A study by the Swedish Energy Agency anticipated that solar power is expected to increase from 0.67 TWh in 2019 to 10 TWh in 2050, assuming continued support from the government, increasing electricity prices & further reduction in the costs of PV systems. [56].

4.1.2 District Heating

The first District Heating (DH) system was established in Karlstad in 1948. In 2017, there were around 500 DH systems in both major cities and small towns. DH has the biggest market share in heat supply to the buildings. Since its inception, DH has gradually replaced fuel boilers. [75]. Figure 16 shows the DH demand since 2000.

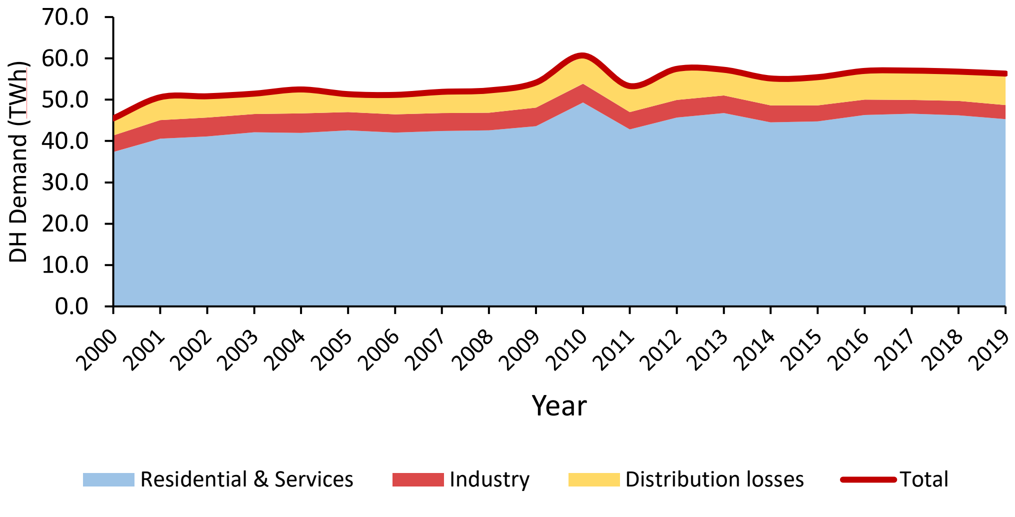


Figure 16: DH demand by sector from 2000 to 2019 [17]

As shown in figure 16, the total DH demand has remained within the range of 50 TWh to 60 TWh since 2001. Residential & Services sector account for more than 80% of the heat demand in DH sector. [17]. The total fuel input to DH was 60.59 TWh in 2019 [60]. Figure 17 shows the fuel supply mix of DH sector in 2019.

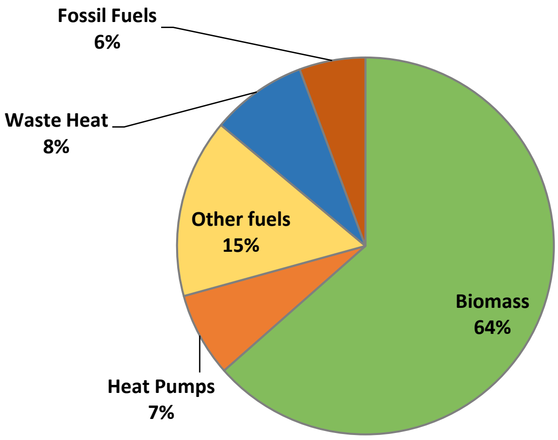


Figure 17: Input fuel supply mix of DH in 2019. Other fuels refer to energy from waste [17]

DH sector principally uses biomass and energy from waste incineration. Fossil fuels such as natural gas, fuel oil, coal, coke oven & blast furnace gases form a tiny fraction of the supply mix as shown in Figure 17. [75], [17]. The extensive use of biomass is enabled by the waste generated by forestry, pulp & paper industries [75].

The Swedish DH system consists of CHP plants, heat pumps, thermal & electric boilers [60]. Biomass is used in both CHP plants & renewable boilers. Waste heat comprises of heat recovered from industries, condensation of flue gases, input to heat pumps etc. In 2014, the total length of pipelines for heat distribution was 23,400 km. The annual distribution losses are in the range of 12%. The distribution network has a temperature difference of 50°C, with an average inlet temperature of 86°C and outlet temperature of 47°C. [75].

Large heat pumps (HPs) in DH systems catered to 7% of total heat demand in 2019 [17]. In 1980s heat pumps, and electric boilers utilized excess electricity produced by nuclear power plants [75]. Large HPs were still operating in 2013, with an installed capacity of around 1224 MWth [76]. However, in recent times, the operational hours of heat pumps have reduced due to an increase in electricity demand & also because of the competitiveness of CHP plants. [75], [76].

Increase in VRES electricity production can change the dynamics of electricity & DH sector in the future. High proportion of VRES may cause significant fluctuation in electricity prices. Time period with higher electricity prices can create favourable conditions to operate CHP plants while hours with lower electricity prices can pave way for PtH via heat pumps & electric boilers. [75], [76]. In addition, new connections to DH systems in the future also depend on the prices of electricity. Lower price levels can make DH less competitive than individual heat pumps. [56].

4.1.3 Industry

In 2019, the industrial sector had a total turnover of SEK 9.494 billion with a value addition of SEK 2.768 billion. Sub-sectors within this sphere are Agriculture & forestry, fishing; Manufacturing industry; trade; construction and services. Manufacturing industries mainly include Metals & Steel, machineries, motor vehicles, paper, chemicals, pharmaceuticals, non-metallic minerals, wood & furniture, electronics and food & beverages [77]. Figure 18 shows the energy consumption in sub-sectors.

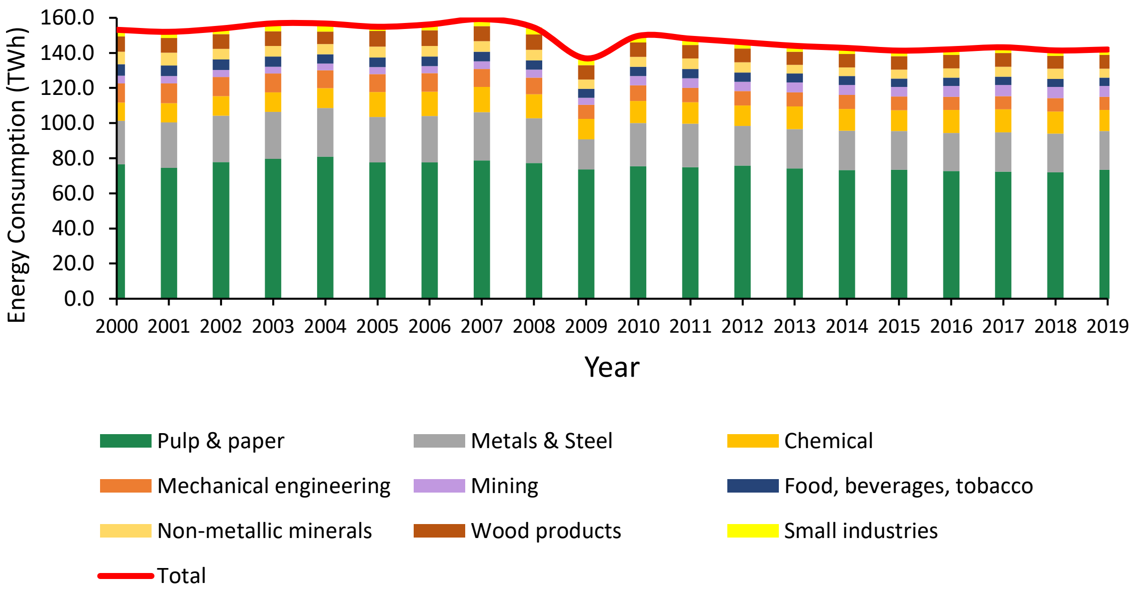


Figure 18: Total energy consumption in the industrial sector by different energy carriers from 2000 to 2019 [17]

As shown in figure 18, pulp & paper industry accounts for around 50% of the total demand, followed by the metals & steel industry (15 to 20%). In 2019, the total energy consumption in the industrial sector was 142 TWh. [17]. Figure 19 shows the composition of fuels that catered to industrial energy demand.

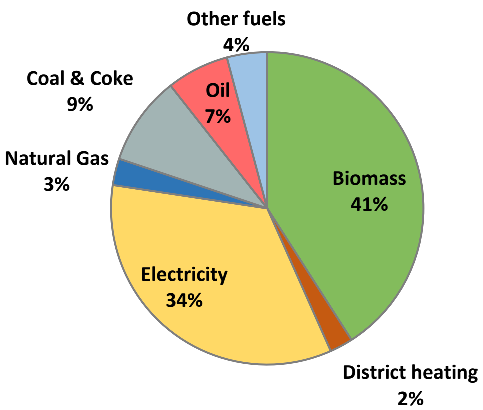


Figure 19: Contribution of various energy sources towards the total energy demand of 142 TWh in the industrial sector in 2019 [17]

As shown figure 19, Industrial sector had a mixed portfolio of energy sources. Pulp & paper which accounts for the highest share of total demand mainly utilized biofuels & electricity. However, iron & steel industry relied heavily on fossil fuels. [18].

The energy demand of steel, metals & mining industry combined was 28.171 TWh (20%) in 2019 [17]. Iron-ore, mostly mined in Norrbotten by LKAB is extensively used in the production of steel. The ore undergoes a reduction process in a blast furnace. The consumption of fossil fuels in this case is primarily due to the use of reducing agents such as coke, pulverized coal, oil or natural gas in the blast furnaces. Therefore, alternative technologies that can substitute the use of fossil fuels have been widely discussed in literature. In this context, the development of hydrogen-based direct reduction method has gained significant interest in Sweden. [78], [56].

In 2016, three prominent players in the industrial sector, Vattenfall, a state-owned energy company; LKAB, an iron-ore mining company & SSAB, a steel production company, started a new venture – HYBRIT (Hydrogen Breakthrough Ironmaking Technology). This joint venture aims to make the production of steel fossil-free by 2035. For this purpose, it seeks to produce hydrogen via electrolysis powered by fossil-free electricity, especially through large-scale integration of wind power. [56], [78], [79],[80].

Other decarbonization projects include CemZero – electrification of cement production, electrification of mines and use of electro-fuels in the future. However, these technological transitions are embedded with uncertainties due to business decisions, market structure and challenges in large scale production of fossil-free hydrogen and so on. [56].

4.1.4 Transport

Transport sector consumes the largest amount of fossil fuels in the Swedish energy system due to heavy reliance on gasoline & diesel in road transport. [56], [17]. The number of vehicles on road is increasing every year. In 2022 there were 4.98 million cars, , 609,000 light trucks, 86000 heavy trucks and more than 14000 buses. Other types of vehicles included snowmobiles (203,000), tractors (384,000), ATVs (104,000) and two-wheelers. [81]. Figure 20 shows energy consumption by the type of transport & energy carrier in 2019.

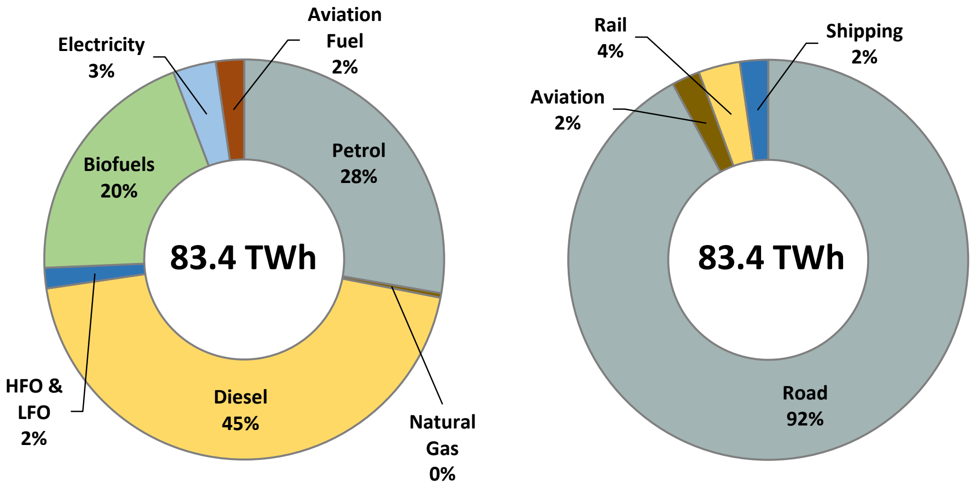


Figure 20a: Energy use in the transport sector in 2019, by energy carrier (left) & Figure 20b by the type of transport. HFO – Heavy Fuel Oil, LFO – Light Fuel Oil (Right) [17], [18]

As depicted in figure 20, the domestic transport sector consumed 83.365 TWh of energy in 2019 [17]. Around 75% of this demand was fulfilled by gasoline & diesel and 20% by biofuels. Natural gas had a very small contribution of 0.3 TWh. Electricity use in all types of transport combined was only 3% or 2.906 TWh. [17], 26). Road transport accounts for the largest share of energy consumption, around 92% [18]. Passenger car fleet represents highest fraction of road transport [81]. Shipping & Aviation depicted in figure 20 constitutes only domestic transport, as international transport is not included in the energy balance. [17].

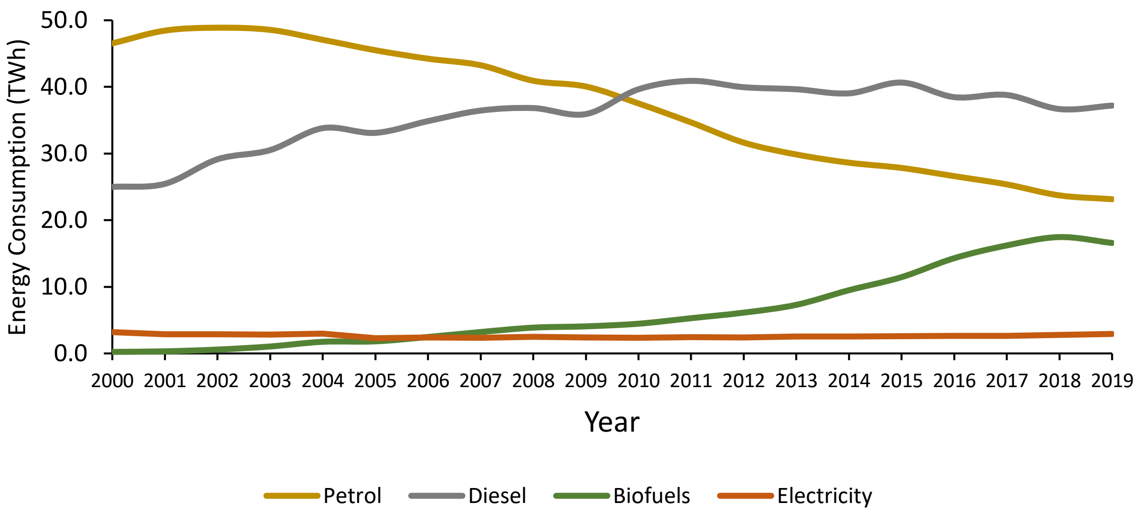


Figure 21: Total energy consumption in the transport sector by different energy carriers from 2000 to 2019 [17]

Since the last two decades, the use of biofuels, especially biodiesel has considerably increased and in contrast, the use of gasoline has significantly reduced as shown in Figure 21. While the demand for diesel has grown, the contribution of electricity has remained within the range of 2 to 3 TWh. [17]. However, there is a growing affinity with EVs in recent years. For instance, the share of EVs among new registrations was 33.5% in January 2021. A year later, BEVs and PHEVs constituted 52% of new sales. In particular, the sales of BEVs increased from 13.1% in Q4 of 2020 to 29.3% in Q4 of 2021. [82].

One of the key targets in Sweden's climate plan is 70% reduction of GHG emissions in the transport sector by 2030 compared to the levels in 2010. The government has set up demonstrative projects & initiatives to increase electrification and develop charging infrastructure in the transport sector. [19].

Along with electrification, an increased share of biofuels in the supply mix can accelerate cost-efficient decarbonization of the transport sector. However, it requires a significant increase in the production of biofuels. [83]. In addition, the elevated demand for biofuels across the world in the future can lead to an increase in prices and thus, a conducive market structure is necessary [56].

4.1.5 Bioenergy

Solid biomass is the major source of bioenergy in Sweden. The domestic potential of solid biomass is quite high as 69% of the land area has forest cover and the country has low population density. [52]3). The energy supplied by biomass was 145 TWh in 2019. [17], [18]. Figure 22 shows the supply of biomass to different sectors since 2000.

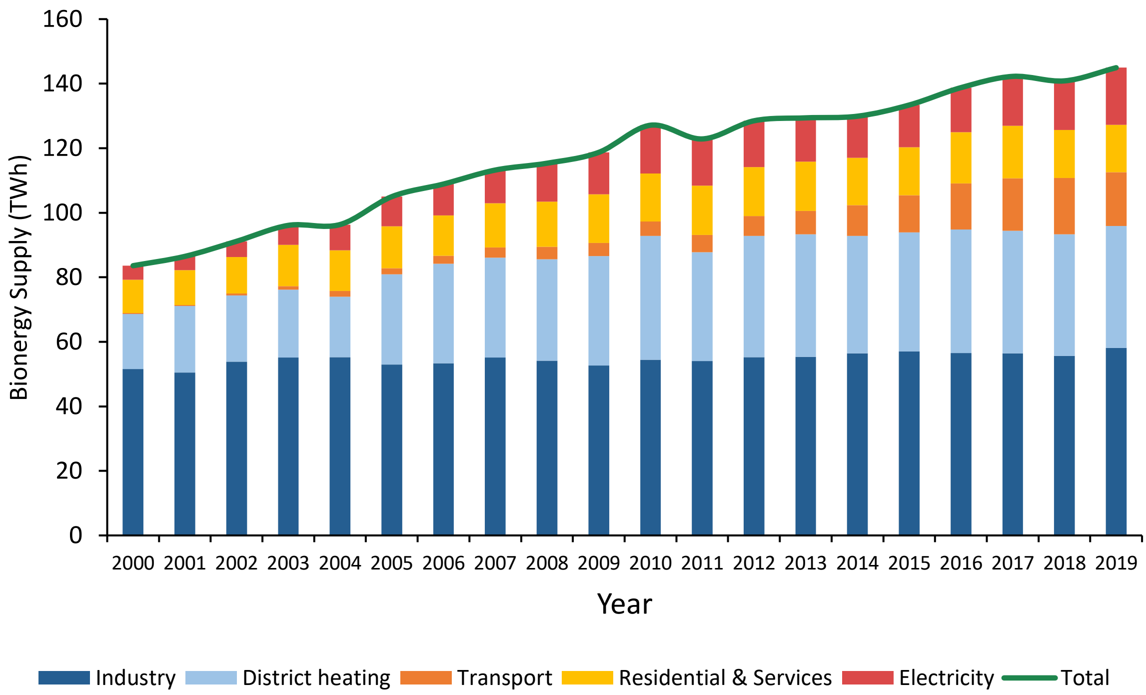


Figure 22: Energy supplied by biomass to various sectors in 2019 [17]

Biomass has evolved as an important source of energy in the Swedish supply mix. It was extensively utilized in DH and industrial sectors in 2019. Biofuel usage in transport sector has gained momentum in the last decade. However, it's usage has remained almost constant in the industry, but has grown steadily in DH. [17], [52], [56]. Biomass is an umbrella term that encompasses a wide variety of fuels derived from organic sources. In the context of Swedish energy system, these fuels include solid biomass, bioethanol, biodiesel, bio-oils, densified and non-densified wood fuels, black liquor, biogas & municipal bio-waste. [17]. Solid biomass dominates this composition mainly in sawmills, pulp, paper industries and DH systems. Liquid biofuels such as bioethanol & biodiesel are mainly used in transport followed by CHP plants. Biodiesel (FAME & HVO) has surpassed the use of bioethanol since 2011. Biogas has a modest share due to its limited role in the substitution of natural gas. Well established waste management systems in Sweden facilitates effective use of renewable municipal waste in the production of heat & electricity. [52], [56].

Bioenergy is expected to play a crucial role in reaching climate targets in the future. Continued growth of biofuels is considered an important factor in the decarbonization of transport sector. [56]. Pulp & paper industry which accounts for the largest energy demand in the industrial sector primarily uses biomass. [18]. Therefore, evolution of biomass in industrial sector in the future is hinged on the progress of pulp & paper [56]. Coupling of Carbon Capture & Storage (CCS) with bioenergy and transport biofuels have gained renewed interest in R&D domain. Bio-CCS projects are in the pipeline in cities like Stockholm, Västerås, Växjö and Södertälje. [52], [56].

4.2 Energy Storage Technologies

Increased electrification of end use sectors coupled with large-scale VRES integration is seen as an important step towards decarbonization of energy sector. However, intermittency of VRES poses challenges in terms of flexibility & curtailment, leading to the consideration of mechanisms to improve flexibility such as demand response, storage etc. [84]. Energy storage offers multiple value propositions such as enabling flexible operation of power system, enhancing reliability, and integrating distributed generation [11]. Energy carriers like electricity or heat can be stored in various chemical or mechanical forms and deployed either at the supply or demand side. [84]. However, incorporating storage in an energy system hinges on the extent of VRES integration, existing flexibility of the system, sector coupling and interconnection of transmission lines [85].

Power and energy capacities are two key parameters that help to determine the application of a given storage technology. Power capacity is expressed in kW or MW. It is the rate at which the storage system can charge or discharge. Energy capacity is expressed in kWh or MWh. It denotes the size of the storage or the total energy that can be stored in a device. [9]. Size of the storage plays a crucial role. For instance, a very small storage system will have negligible impact on energy system performance while a very large storage system will augment investment & operational costs. Therefore, determining storage capacity is an interesting optimization problem and has paved way for application of AI based optimization algorithms. [86]. Further, the choice of a storage technology also depends on its characteristics such as storage medium, duration - short or long term, type of energy carrier, round-trip efficiency, scale of implementation, costs & sector [87].

Energy storage systems encapsulate a variety of technologies depending on the type of energy carrier, storage medium, duration & mechanism. Tables 2 & 3 give an overview of current technologies in this arena. [11].

Table 2: Overview of different storage technologies [11]

Technology	Storage Medium	Working Principle
Pumped Hydro-electric Storage (PHS)	Water	Water is pumped to upper reservoir during off-peak hours. It is released back to lower reservoir to generate electricity during peak hours.
Compressed Air Energy Storage (CAES)	High pressure air	During off-peak hours, Air is compressed via compressors and stored in underground cavern (large-scale) or storage tanks (small-scale). Compressed air is heated & released to turbines during peak hours.
Flywheel Energy Storage (FESS)	Mechanical	Motor/Generator unit is used to accelerate the flywheel to store energy & decelerate to extract stored energy. High speed systems contain magnetic bearings to improve durability & performance.
Battery Energy Storage System (BESS)	Electrochemical	Electrochemical reactions enable charging or discharging actions. Lead-acid, Lithium-ion, Nickel-Cadmium etc. are some of the common types. BESS is further discussed in section 5.1.
Flow Battery	Electrochemical	Electrolytes from two different sealed tanks (one for anode & another for cathode) are pumped into the cell stack. The electrodes are separated by an ion selective membrane. During charging, the electrolyte in anode is oxidized while the one in cathode is reduced. The process is reversed during discharging.
Super Capacitor	Static Charge	The device contains two electrodes and electrolyte separated by a porous membrane. It has characteristics of both conventional capacitors & batteries. Energy is stored as static charge on the surface between the electrode & electrolyte.
Superconducting Magnetic Energy Storage (SMES)	Magnetic field	Direct current passed through a superconducting coil with zero resistance creates a magnetic field. Energy stored in the magnetic field is discharged as alternating current via a power electronic converter. Niobium-Titanium is the commonly used material that exhibits superconducting behaviour at 9.2 K. A refrigeration unit is employed to maintain this temperature.
Hydrogen Storage	Hydrogen	Electricity is used to produce hydrogen by electrolysis of water. It is stored in containers and then used in fuel cells to produce electricity. Further discussed in section 5.2.
Thermal Energy Storage (TES)	Water, PCM, Molten Salt, Concrete, Synthetic Oils	Charging & discharging of heat varies depending on the type of TES. Application of TES is also extensively explored in research in the context of PtH (Power to heat) and sector coupling of electricity & district heating. It is further discussed in section 5.3.

Table 3: Technical characteristics of storage technologies [11]

Technology	Power Rating (MW)	Storage Capacity (MWh)	Lifespan (Years)	Charge-Discharge Cycles	Round-trip efficiency (%)	Storage Duration	Maturity level
PHS	100 – 5000	500 – 8000	40 – 60	10,000 – 30,000	70 - 85	Hours to Months	Mature
CAES (Large-Scale)	Around 300	1000	20 - 40	8000 - 12000	40 - 50	Hours to Months	Developing
Flywheel	0.25 – 20	0.75 – 5	15 – 20	20000	90 - 95	Minutes to < 1h	Early commercial stage
Supercapacitor	0.001 – 0.1	0.0005	10 - 30	100,000	90 - 97	Seconds to hours	Developing
SMES	0.1 – 10	Up to 0.0015	20	100,000	95 - 98	Minutes to hours	Developing

Pumped Hydro-Storage (PHS) is the most widely used storage technology with a global capacity of 8500 GWh. It constituted 90% of the total electricity storage in 2020. [12]. Nevertheless, in recent years, grid-scale & behind-the-meter battery storage is gaining momentum due to reduction in costs. Evolution of EV market has paved way for Vehicle to Grid (V2G) storage. [8]. Grid-scale storage is anticipated to provide both short-term (balancing and ancillary services) and longer-term storage in the decarbonized energy systems of the future (2050). [12]. However, instead of focusing only on electricity storage that offers limited flexibility options, exploiting the advantages of sector coupling & other forms of storage such as TES can unlock better avenues. [13]. Further, the need for large-scale & seasonal storage in the future VRES systems has sparked renewed interest in hydrogen as an alternative energy carrier. [8].

4.2.1 Hydrogen Storage

Hydrogen (H_2) is the lightest element in the universe [88]. It is a colourless, odourless, and nontoxic gas [89] and has the lowest molecular mass (2.016 g/mol) and density (0.084 kg/m^3) at standard atmospheric conditions [88]. The global demand for pure hydrogen & hydrogen in a gas mixture are 70 Mt and 45 Mt respectively. Pure H_2 is mainly used in the production of ammonia and in oil refineries. Gas mixture containing H_2 is used in the production of steel and methanol. [90]. Different colour codes are assigned to hydrogen depending on the source & method of production, as shown in Table 4 [88].

Table 4: Production of H2 from various sources and corresponding colour codes [88]

Source	Process	Colour Code
Coal	Gasification	Brown Hydrogen
Natural Gas (NG)	Steam Methane Reforming (SMR)	Grey Hydrogen
Coal / NG with CCS	Gasification / SMR	Blue Hydrogen

Nuclear Power	Electrolysis	Yellow Hydrogen
Renewable Energy	Electrolysis	Green Hydrogen

Currently, more than 60% of global supply comes from production facilities wherein H_2 is the primary product. Rest of the supply is fulfilled by industries where it is a by-product. Hydrogen industry is dominated by fossil fuels. 76% of 70Mt of hydrogen is produced from natural gas (205 billion m^3 or 6% of global natural gas demand), followed by 23% from coal (107 Mt or 2% of global coal demand), leading to annual GHG emissions of 830 Mt-CO_2. Production from renewables and fossil fuel with CCS constitute less than 0.7%. [90].

In recent years, hydrogen as a fuel has gained significant interest in the global energy landscape. It has the potential to drive the energy sector towards net-zero target. [88]. Hydrogen is part of decarbonization strategy published by the European commission. The EU member countries signed the Linz declaration known as “Hydrogen Initiative” aimed to promote sustainable hydrogen technology. [90].

Development of hydrogen infrastructure can address the challenges posed by intermittent VRES-based electricity by coupling electricity, industry, and transport sectors. In such a system, fluctuating electricity prices is also a driving factor in incorporating hydrogen storage to improve revenue for base-load plants. [51]. Seasonal storage of helps to enhance flexibility & maximize the benefits of VRES integration by bridging the gap between demand and supply due to seasonal effects [35].

Hydrogen is produced via different methods – Reforming, gasification, and electrolysis of water. SMR is the most widely used method wherein steam is used to produce hydrogen from natural gas. Other reforming techniques include partial oxidation (oxygen is used as an oxidant) using heavy fuel oil & coal and autothermal reforming – a combination of SMR and partial oxidation. [90]. Electrolysis is a chemical process of redox reaction that uses electricity to split water into its constituent elements – hydrogen & Oxygen [42].

Production of green hydrogen via electrolysis is seen as a crucial component in the future energy systems [35]. However, it creates an additional demand for RES electricity and water. For instance, around 3600 TWh of electricity and 617 million m^3 of water will be required to fulfil current global hydrogen demand (69 Mt) by electrolysis. This additional demand for water can be an issue in the areas prone to scarcity. [90]. Although electrolyser-fuel cell combination does not cause any GHG emissions, the current technology is much more expensive than Li-ion batteries. [42].

Capacities of electrolysers in current projects are within 10 MWe. A 20 MWe is under construction and 100 MWe is proposed in many upcoming projects. [90]. Electrolysers can be broadly classified into three main types. They are Alkaline Electrolysis Cells (AEC), Proton Exchange Membrane Electrolysis Cells (PEMEC) and Solid Oxide Electrolysis Cells (SOEC) as illustrated in table 5 [35], 102).

Table 5: Techno-economic characteristics of AEC, PEMEC and SOEC [90],[91]

Characteristics	AEC	PEMEC	SOEC
Electrolyte	Potassium Hydroxide	Polymer Membrane	Yttria stabilized Zirconia
Cell Voltage (V)	1.8 – 2.4	1.8 – 2.2	0.7 – 1.5
Current density (A/cm^2)	0.2 - 0.4	0.6 – 2	0.3 - 2
Operating Temperature (^{o} C)	60 – 80	50 – 80	650 - 1000
Operating Pressure (Bar)	1 – 30	30 – 80	< 25
Stack lifespan (operating hours)	60,000 – 90,000	20,000 – 60,000	10,000 – 30,000
Electrical Efficiency (LHV) (%)	63 – 70	56 – 60	74 – 81
Phase	Most mature & commercial	Commercial but less deployed compared to AEC	Least developed and still in demonstration
CAPEX (USD / kWe)	500 – 1400	1100 – 1800	2800 – 5600

AEC is the most widely used technology for large-scale applications due to low capital costs & other techno-economic benefits compared to PEMEC & SOEC [42]. CAPEX costs are low due to the absence of precious metals. But its operation is limited to low pressure range and has low flexibility leading to high production costs. [90], [91].

PEMEC was introduced by General Electric in 1960s to address some of the limitations in AEC. It is relatively less matured technology compared to AEC and is used mostly in small-scale applications. Although it has better efficiency and flexibility, the system cost is high due to expensive catalysts (Iridium, Platinum) and membrane materials. In addition, the system has high complexity and shorter lifespan compared to AEC. In the last decade, many PEMEC projects have been installed in Europe. Due to high degree of flexibility, PEMEC can support frequency reserve and ancillary services. [91].

SOEC is still in the development and demonstration phase. Even though it is highly efficient, has comparatively low material costs and can operate in reverse mode as fuel cell, it undergoes acute material degradation due to high operating temperatures. Since it can also operate as a fuel cell, in conjunction with hydrogen storage, it can provide grid balancing services. [91].

High capital costs and current limitations in performance are the hurdles to invest in electrolysis projects. Studies show that PEMEC is expected to takeover AEC in the coming decade. But the future of SOEC is still uncertain due to higher CAPEX and lower lifespan compared to AEC & PEMEC [91].

Cost of hydrogen depends on the method of production, type of fuel and overheads associated with transmission & storage. Since more than 90% of hydrogen is produced via SMR, price of natural gas is an important factor in the production cost. For instance, production cost is low in the middle east, North America & Russia due to low gas prices compared to countries that import natural gas such as China, India, Japan & Korea. Addition of CCS unit further increases the cost. In Europe, the production costs of grey hydrogen (1.7 USD / kgH_2) and blue hydrogen (2.4 USD / kgH_2) are significantly lower than green hydrogen (3 to 4 USD / kgH_2). In the coming decades, cost of green hydrogen will mainly rely on technological advancement, price of electricity and economies of scale. Especially in countries with significant share of RES-based electricity, hydrogen from electrolysis may become a cheaper option compared to SMR. [90].

The design of storage and delivery infrastructure to support long-term and large-scale hydrogen storage plays a crucial role in flexible future energy systems. Currently, 85% of the hydrogen produced is consumed onsite and only 15% is transported via trucks or pipelines. [90]. Hydrogen has high energy content per unit mass compared to other fuels such as gasoline. But its energy density (33.3 kWh/kg) is very low and hence, requires large volume for storage. [46], [89].

Compressed hydrogen can be stored in different ways depending on the pressure, storage duration, scale, geographical area, costs, safety measures etc. Storage systems can be bifurcated into two main categories – pressure vessels or tanks, geological and underground storage. [92]. Other short-scale storage mechanisms include absorption by carbon nano materials, storage on metal hydrides and oxidation of some reactive metals. [88]. Storage tanks encapsulate compressed or liquified hydrogen. They have high discharge rate and have an efficiency of 99%. [90]. Hydrogen can be compressed and stored in high pressure tanks (700 bar). Liquified and cryogenically cooled (-253 ^{o}C) hydrogen is stored in insulated tanks with pressure ranging from 6 bar to 350 bar. [89]. Principal types include seamless vessel, stell-concrete composite vessels, multi-functional steel layered vessels and natural gas storage facilities. [92].

Underground hydrogen storage (UHS) is mainly associated with large-scale storage. It is a promising but poorly understood avenue. [88]. Aquifers, salt & rock caverns, depleted oil & natural gas reserves, abandoned mines are the main categories in UHS [92]. Geological storage is the best option for seasonal and large-scale storage. [90]. Although UHS is one of the cheapest options, it depends on geographic terrain. Residual matter such as rocks, fluids or micro-organisms in aquifers and depleted oil or gas reservoirs contaminate stored hydrogen [92]. However, addition of an impermeable layer of rocks to an aquifer is anticipated to minimize the risk [35]. Contamination is negligible in salt caverns [92]. Current research shows that salt cavern is the most suitable option compared to aquifers or depleted oil or gas reservoirs [88]. Salt caverns are mainly used by the chemical industries. The storage cost is less than USD 0.6 / kgH_2, have high discharge rate and efficiency is 98% with a very low risk of contamination. [90]. But one of the biggest challenges in UHS is the availability of salt cavern, aquifers, oil, or gas reservoirs etc. in a geographical area [88].

Long distance transmission and distribution of hydrogen can be expensive due to its low energy density. Thus, building a new infrastructure would require enormous investment. But, utilizing existing natural gas infrastructure – 3 million kms of pipeline and 400 billion m^3 of storage worldwide, by blending hydrogen presents a better alternative as it would significantly reduce the capital costs. However, blending has its own challenges due to lower energy density of hydrogen compared to methane, risk of flames as it burns faster than methane and degradation of the equipment. [90]. Studies show that transmission as a gas via pipeline is the cheapest option (USD 1 / kgH_2) for distance lesser than 1500 km. Pipelines have low OPEX and lifespan of 40 – 80 years. In case of longer distances, transport of ammonia instead of pure hydrogen can be the most cost-effective option since ammonia can be liquified at -33^{o}C compared to hydrogen at -253^{o}C. [90].

An interesting avenue under consideration is the production of hydrogen via surplus electricity in a VRES-based energy system, compared to alternatives such as batteries and PtH. Even if surplus electricity is available at a lower price, this option can become competitive only when the surplus production hours are more than 2100 hours. [93], [90].

Conversion of hydrogen to electricity can be achieved in two methods –open or combined cycle operation of gas turbines and fuel cells. [93]. Gas turbines driven by a mixture of hydrogen and methane or bio-methane, or 100% hydrogen are more competitive in wind dominated VRES systems compared to solar PV, provided there is an additional constraint on generation by fossil-fuels. [94]. A hydrogen fired gas turbine is used to generate heat (2.8 MWth) and electricity (1.1 MWe) for a local community in Japan. [90].

Fuel Cells (FCs) produce electricity and heat with a conversion efficiency of 40 – 60% [95]. They perform better in part load than full load and hence, provide an interesting option for flexible operation [90]. FCs consist of anode, cathode, and non-conducting electrolyte [96]. They find applications in automobile industry (EVs) and in buildings to produce electricity (& heat). Today, Fuel Cell Electric Vehicle (FCEV) fleet mainly consists of light-duty vehicles like passenger cars (74%), followed by buses (16%) and other commercial vehicles. Since 2008, cost of FCEV systems has reduced by 70% and currently varies between 250 – 400 USD/kW. Major automotive companies in the transport industry have announced ambitious targets in the development & deployment of FCEVs by 2025 – 2030. Stationery FCs are mainly deployed in residential sector in Japan (350,000 units), Germany (15,000 units), Belgium & France. [97]. CAPEX of FCs varies between 1500 – 3000 USD / Kw [95].

Major fuel cell technologies are – Polymer Electrolyte membrane fuel cell (PEMFC), Phosphoric acid fuel cell (PAFC), Molten Carbonate Fuel Cell (MCFC), Solid oxide fuel cell (SoFC) and Alkaline Fuel Cell (AFC). [90], [97]. Characteristics of different fuel cells are listed in table 6.

Table 6: Characteristics of fuel cells [90],[95],[96]

Type	PEMFC	PAFC	MCFC	SoFC	AFC
Electrolyte	Perfluoro sulphonic acid	Phosphoric acid	Molten carbonates	Yttria stabilized zirconia	KOH
Temperature (°C)	50 - 120	150 - 200	600 - 700	700 - 1000	90 - 100
Efficiency	Stationery (35%),	40%	45 – 50%	60%	60%

	Transport (60%)				
Stack Size	Up to 100 kW	100 – 400 kW	300 kW – 3 MW	1 kW – 2 MW	10 – 100 kW
Application	Distributed generation, Backup power, transport	Distributed generation	Distributed generation, Utility-scale	Distributed generation, Utility-scale	Space, Military

Installed capacity of FCs at global level reached 1.6 GW in 2018. Nevertheless, most of the existing installations run on natural gas, while only a tiny fraction uses H_2 as fuel (70 MW). FCs can substitute diesel generators to cater to back-up power & off-grid applications in the future. However, this evolution relies on technological breakthrough and reduction in investment costs. [90].

In Sweden, the footprint of fossil fuels is very low in electricity and DH sectors, but quite significant in transport & industries. [17], 11, 26). Green hydrogen, biomethane etc. are expected to play a major role in decarbonisation of these hard to abate sectors. Currently, the demand for hydrogen in the country is mainly from chemical industries. Total hydrogen production is around 6 TWh wherein 4 TWh is produced by gas reforming process and 2 TWh is the result of industrial processes. Production via electrolysis constitutes a negligible amount. [98].

Although hydrogen plays a minor role today, it is anticipated to be a major component in Steel Industry in the future. As mentioned in the previous chapter (4.3), HYBRIT is an ambitious initiative aimed to decarbonize iron & steel industry by implementing Hydrogen-based Direct Reduction of Iron ore (HDRI) technology via green hydrogen. [98]. Today, more than 60% of steel is produced by iron-ore in a blast furnace-based system. Rest of the production is from Steel scrap that requires electric arc. GHG emissions from iron and steel industry is mainly due to the use of fossil fuels (pulverized coal, natural gas, oil) in blast furnace. The concerned stakeholders hold the view that HDRI is the best option among the existing sustainable alternatives. [78].

In this context, Studies show that the demand for hydrogen is expected to increase from 6 TWh today to 50 – 68 TWh in 2045 due to significant substitution of fossil fuel-based technologies in industry and transport. However, the pathway to this scenario presents following barriers. [98].

1. Technical expertise is limited and only prevalent in specific industries in SE3 & SE4.
2. Lack of clarity on funding hydrogen infrastructure projects from the government and concerned stakeholders.
3. Cost-effective hydrogen storage potential is limited due to unavailability of natural geological formations. For instance, Sweden does not have large gas storage facilities. A small Lined Rock Cavern (LRC) storage with a capacity of 8.8 million m^3 near Skallen is in operation to cater to peak demands.

4. Extension of current regulatory framework and market conditions is required to address barriers for entry.
5. Uncertainties in the evolution of electricity supply mix in the future and the limitations of transmission capacity.
6. Lack of specific targets pertaining to long-term development of hydrogen infrastructure.

4.2.2 Thermal Energy Storage

Thermal energy can be stored by heating, cooling, vaporizing, melting or solidifying a material. The energy thus stored can be retrieved later by reversing the process. [99]. Thermal Energy Storage (TES) is primarily utilized in heating, cooling & power generation applications [84]. It has very low self-discharge and can store large amount of energy [11]. It consists of a broad spectrum of technologies. Based on the working principle they are classified into four groups as mentioned below. [84].

1. Sensible Heat Storage
2. Latent heat storage or Phase Change Materials (PCM)
3. Thermochemical storage or Thermochemical materials (TCM)
4. Mechanical-thermal coupled systems

In Sensible storage, heat is stored as internal energy of the material (solid or liquid) by increasing the temperature. It is later extracted by decreasing the temperature. The phase of the material remains the same. In general, types of storage materials include rock, sand, salt, concrete, aluminium, steel, molten salt, thermal oils, water etc. [100]. Storage capacity (Q Joule) depends on the temperature gradient (dT), mass (m kg) and specific heat of the material (Cp J/kg-K) as shown in equation XX, where T1 & T2 are initial & final temperatures respectively in Kelvin. [99].

$$Q = m \int_{T_1}^{T_2} C_p(\mathrm{T})\, \mathrm{dT} \ldots\ldots\ldots\ldots\ldots\ldots.(1)$$

Depending on the material, the storage capacities vary between 10 kWh to 50 kWh per tonne, operating temperatures between -160°C and 1000°C and efficiencies between 50% to 98%. However, the storage density is quite low and leads to high volumetric requirements. Also, in case of high operating temperatures or longer storage duration, additional insulation is required to inhibit high levels of self-discharge. [84]. Storage materials include rock, sand, ceramic bricks, concrete, silica, oxides of magnesium, aluminium, molten salt, ethanol, butane, therminol, water and so on [84], 96). Compared to liquid media, solids facilitate wider operating temperature range [100]. Storage mechanism in sensible storage mainly consists of tank type storage (TTES) and UTES (Underground TES) [84]. Table 7 shows the distinction between these two technologies.

Table 7: Characteristics of two different Sensible storage - TTES & UTES [84],[100]

TTES	UTES
Heat is stored in a tank. Simplest and most common TES technology.	Heat is stored underground. This technology can be further classified into 3 types – Aquifer TES (ATES), Borehole TES (BTES) and Pit TES (PTES).
Storage duration varies from few hours to few days. System consists of a storage tank, heating apparatus and heat exchanger.	Facilitates long-term (seasonal) storage to facilitate cooling in summer and heating in winter.
Water is the most widespread storage medium. System consists of a storage tank, heating apparatus and heat exchanger.	ATES uses water. It has hot and cold wells. Pits are insulated in PTES and contain gravel and water. BTES uses mixture of soil that has high specific heat, with water in vertical heat exchanger as working fluid.
Volume of the tanks vary between few hundred litres in small scale residential applications to as high as 80,000 m^3 in large-scale applications such as industries or district heating.	UTES require large volume and is mainly used in buildings (ATES) and district heating. Some systems require heat pumps for discharging and (or) charging.
TTES is the most matured technology.	While UTES is relatively functional in some countries, it is still under development and demonstration phase in many places.

As mentioned in table 7, Sensible storage, especially with water as the medium is the most implemented type among existing TES categories, as it is the simplest & cheapest technology. [84]. Due to its abundant availability, incombustible and non-toxic properties, water is used in both domestic and large-scale TES systems [84], 96). Another TTES variant is the molten salt storage. It can store heat at high temperatures (290° C to 550° C). It is primarily used in Concentrated Solar Power (CSP) plants wherein the heat stored during the day is used to drive the steam turbine at night to ensure continuous production of electricity. [100].

In Latent heat storage, heat is used to change the phase of materials to harness storage. PCMs capture latent heat of fusion (solid to liquid phase) and latent heat of vaporization (liquid to vapour) to store energy. The storage capacity Q is defined by the equation XX. [99].

$$Q = \int_{T_i}^{T_m} mC_p dT + ma_m \Delta H_m + \int_{T_m}^{T_f} mC_p dT \quad Joule \text{............(2)}$$

Where m = mass of storage medium (kg), C_p = specific heat of the material (J/kg-K), a_m = fraction that is melted, ΔH_m = heat for melting per unit mass (J/kg), T_i = Initial Temperature (K), T_m = Intermediate Temperature (K) and T_f = Final temperature (K).

The storage material or PCMs can be broadly divided into four categories: Solid-Gas, Liquid-Gas, Solid-Liquid and Solid-Solid. Solid-Liquid type of PCMs include both organic and in-organic compounds such as Paraffin, Fatty acids, Molten salts, Salt hydrates etc. [99]. In terms of temperature, PCMs can be classified as low temperature (< 15° C) – Ice, salt-water mixtures, water gel; medium temperature (15° C to 90° C) – Salt hydrates, paraffin wax; high temperature (> 90° C) – Molten salts, metal alloys. [84], 95). Latent heat storage has higher energy density compared to sensible storage. In addition, since they can charge or discharge at constant temperatures, they find applications in many sectors such as refrigeration, textiles, aerospace, buildings, solar energy and so on. [84], 95).

Ice, due to its availability, conducive material and chemical properties (latent heat of 334 kJ/kg), is used in TES systems for buildings and district cooling. Paraffin waxes are low cost PCMs and have wide range of melting temperatures and moderate latent heat (200 kJ/kg). However, their application is limited due to low thermal conductivity and flammability. Inorganic salts have high phase change temperatures (> 500° C), are chemically stable and provide high storage density. However, charging and discharging rates are limited as they are corrosive and have low thermal conductivity. [84].

Thermochemical Storage comprises of two methods – reversible reaction and sorption [84], 97). In reversible reaction, energy is stored in chemical bonds, whereas it is stored in physical bonds in case of sorption [101]. Reversible reactions include redox reactions, chemical looping and metal hydrides. Chemical looping is mainly studied in the context of carbon capture by utilizing the reversible reaction between Carbon-di-oxide (CO_2) & Calcium oxide (CaO) to form Calcium carbonate ($CaCO_3$). Sorption systems include adsorption & absorption and incorporate salt hydrates, liquid and solid based sorption. [84], 97).

TCMs provide higher energy density compared to sensible storage and PCMs. In addition, they also facilitate long-term and seasonal storage. [101]. However, currently they have lower round-trip efficiency (45 to 63%) compared to sensible storage (50 to 90%) and latent heat storage (around 90%). Further, the existing technologies are still in evolution phase and are not available for large-scale commercial deployment. [84].

Mechanical-thermal coupled systems are being studied to explore complementary benefits by coupling mechanical and TES systems. Some examples are Adiabatic Compressed Air Energy Storage (A-CAES) and Liquid Air Energy Storage (LAES). A-CAES systems have an added TES system to the conventional CAES to minimize conversion losses in gas compression stage. In LAES, compressed air is further liquified for storage and transportation. Both technologies exhibit high round-trip efficiency (90%) but are still in the demonstration phase. [84].

In essence, among all TES categories, Sensible storage with TTES (Water, Molten salt) & UTES are the most matured technologies. High temperature PCM and TCM based systems are still under research to demonstration phase, expected to advance in the coming decade. [84].

As of 2019, active TES systems across the world had a total storage capacity of 234 GWh. IRENA's 'transforming energy scenario' anticipates this capacity to increase up to 800 GWh by 2030. District heating accounts for the largest share (53%) of current capacity of TES. TES in DH systems aid decoupling of demand and supply. Most common application of TES in power sector is the deployment of molten-salt storage in conjunction with CSP plants. Current capacity at global level stands at 21 GWh. The future of molten-salt storage is hinged on the evolution of CSP. Application of TES in industry is still at the nascent level. Solar thermal systems with TTES for low temperature heat is growing in mining, textile and food industries. Austria, Germany, France, China, India & Spain are the key target markets. [84].

TTES & UTES are the widely deployed technologies in DH systems. PCM storage with Ice as the medium is mainly used in district cooling. ATES enables large scale & seasonal storage. [84]. There are around 2800 ATES projects worldwide with a capacity of 2.5 TWh that cater to heating and cooling demands. 85% of these systems are in the Netherlands, 10% in Denmark, Sweden & Belgium. Rest of the world accounts for only 5%. However, in recent years, Germany, Japan, China & Great Britain have shown interest in ATES. [102].

Sweden has extensive DH networks that cater to heat demand in residential, commercial, and industrial sectors. The TES systems attached to DH help to tackle daily load variations. As of 2016, the total storage capacity was 900,000 m^3 volume of hot water or 150 TJ (41.67 GWh). [75]. The world's largest ATES system with a storage capacity of 9 GWh is at Arlanda airport in Stockholm. The volume of this aquifer is 200 million m^3. It has reduced annual energy consumption of the airport by 19 GWh. [84].

In a VRES based energy system, integration of electricity and DH sectors via PtH and TES enable sector coupling, improve flexibility, decouple demand-supply, and reduce curtailment of excess electricity. [52]. However, following challenges must be addressed to effectively harness the benefits of TES. [84].

1. TES technologies such as PCMs & TCMs are still in research or demonstration phase.
2. Lack of knowledge and awareness about TES systems.
3. Policies and planning lack sector coupling approach.
4. Development of TES heavily relies on the evolution of future energy systems.

4.2.3 Battery Storage

A battery energy storage system (BESS) comprises of electrochemical cells. An electrochemical call has two terminals – anode and cathode separated by an electrolyte. Electrolytes can be solid, liquid, or viscous substances depending on the type of the battery. The cells are connected in series / parallel configuration to reach required voltage level. Rechargeable batteries are the basic building blocks of BESS. They cater to a wide range of applications in electronic devices, EVs and power systems. [11].

BESS is the most scalable form of storage [12]. It is an effective solution to improve flexibility due to fast response time and high efficiency compared to other technologies [113]. In addition, it is also considered an important part of Demand Side Response (DSM), especially in conjunction with distributed solar PV units. [103]. Compared to PHS that offers ramp-up rates between 10 – 30 % per minute, the response time of BESS is in the order of milliseconds to seconds. Further, it can be incorporated in any stage of the electricity supply chain i.e., generation, transmission & distribution. [104].

Battery market has witnessed significant growth in recent years, mainly in the US, China, and EU. Around 10 billion USD was invested in 2021 on a global scale. Investment is expected to double in 2022. The total installed capacity of BESS world-wide was 16 GW in 2021. This capacity must be augmented to 680 GW by 2030 to accelerate net-zero emissions. [12]. UK and Germany are leading the BESS market in Europe with installed capacities of 570 MW &

406 MW respectively. However, UK & Ireland are at the forefront in upcoming projects. [105]. A recent study showed that BESS has better potential in frequency regulation compared to energy arbitrage in the EU electricity market, especially in countries with significant PHS and other flexibility mechanisms. [106].

BESS is classified into different types based on the materials used in anode & cathode that cause various electro-chemical reactions to enable current flow. Characteristics of these batteries are listed in table 8 [11].

Table 8: Characteristics of different batteries [11], [107],[108],[109],[110],[96],[112]

Type	**Lead-acid**	**Lithium-ion**	**Nickel-cadmium (Ni-Cd)**	**Nickel-Metal hydride (Ni-MH)**	**Sodium-Sulphur (NaS)**
Anode	Pb	Graphite	Cadmium	Hydrogen absorbing alloy	Molten Sodium
Cathode	PbO_2	$LiCoO_2$, $LiMO_2$	Nickel hydroxide	Nickel hydroxide	Molten Sulphur
Electrolyte	Sulphuric acid	$LiClO_4$	Alkali Solution	Alkali Solution (KOH)	Beta alumina
Unit Voltage	2 V	3.7 V	1 – 1.3 V	1 – 1.3 V	2.08 V
Round-trip efficiency	63 – 90 %	Up to 97 %	60 - 70 %	60 – 70 %	75 – 90 %
Cycles	Up to 2000	500 – 10,000	2000 - 2500	1000 - 5000	More than 4500
CAPEX (USD/kWh)	50 - 600	300 - 900	800 - 1500	250 - 1500	2500 - 4500
Energy Density	50 – 90 Wh/L	250 – 670 Wh/L	60 – 150 Wh/L	170 – 420 Wh/L	150 – 300 Wh/L
Specific Energy	25 – 50 Wh/kg	100 - 265 Wh/kg	50 – 75 Wh/kg	70 – 100 Wh/kg	150 – 240 Wh/kg
Advantages	Matured technology; inexpensive; low self-discharge; high power output	Relatively low maintenance; absence of memory effect; fast and efficient charging	Highly reliable; fast charging; long shelf life under discharge	Low memory effect compared to Ni-Cd; safer than Li-ion batteries; Few toxic materials	Fast response; safer than Li-ion; Zero self-discharge; high storage & power capacity; long discharge time (> 6h)
Application	Telecom, EMS, HEVs, EVs	Electronic devices, EVs, balancing & frequency regulation	Electronic devices	EVs, HEVs, UPS	Grid stabilization, frequency regulation, EMS
Limitations	Limited depth-of-discharge; low cycling time and energy	Overheating & thermal runaway, aging, and increased weight due	Ni & Cd are highly toxic materials; suffers from memory effect; not	High Self-discharge; degradation in performance after few	High operating costs; requires external heat source to maintain high operating

	density; poor performance at low temperatures; hazardous material (Lead)	to additional safety mechanisms.	suitable for grid-storage	hundred cycles,	temperatures (300°C – 350°C); requires additional safety measures

Apart from the types mentioned in table 8, other BESS technologies include flow batteries, Na-ion & Zinc batteries [104]. A Flow Battery Energy Storage (FBES) system consists of two tanks – one for anode and another for cathode. Each tank contains electrolytic solution, and the tanks are separated by ion selective membrane. During charging, the electrolyte in anode tank undergoes oxidation while the one in cathode undergoes reduction. The process is reversed during discharge. [11]. Since the liquid electrolytes are isolated, FBES has low internal discharge and long cycle life. Nonetheless, FBES systems have complex requirements, low energy density and high costs compared to conventional BESS. [109]. The technology is still in the demonstration phase due to technical and financial limitations. Types of FBES include vanadium redox FB, zinc bromine & polysulfide bromine FB. [11].

Li-ion batteries (LIB) are employed in a wide spectrum of applications – electronic devices, EVs, Hybrid RES systems, micro-grids, grid-scale storage, balancing markets & frequency regulation due to their availability in different sizes & shapes, high energy & power densities, and conversion efficiency. [113]. They have dominated the short-term grid-scale storage sector in recent years. This trend is expected to continue in the coming decade. [107], [12]. Primary LIB types include Li-Cobalt Oxide (500 to 1000 cycles), Li-Manganese Oxide, Li-Nickel Manganese Cobalt Oxide (NMC), Li-Iron phosphate, Li-Nickel Cobalt Aluminium Oxide (NCA) & Li-Titanate. Li-Titanate has the longest lifespan (3000 – 10,000 cycles) and best performance but is quite expensive compared to its counterparts. [113], [110]. Lithium Iron phosphate is the preferred choice in grid-scale applications due to energy density and cost. However, NMC & NCA are used in applications with space constraints such as home storage systems. [12].

The price of LIB has substantially decreased in the last decade. Nevertheless, further reduction relies on the price of minerals, especially Lithium, nickel, cobalt, and graphite. The Russia-Ukraine war has impacted this market since Russia is the major producer of Class 1 nickel, cobalt & graphite. [12]. Extensive deployment of LIB based BESS in grid-storage and EVs drives the demand for Lithium, Cobalt, Nickel, Manganese, and graphite. Mining and supply of these minerals entail social, economic & environmental impact in addition to the existing challenges in improving energy density, performance & safety. Therefore, energy transition in the future heavily relies on the availability and sustainable procurement of these minerals. [114]. Japan and South Korea are steering the global battery race. Innovations in Li-ion batteries are driven by its wide spectrum of applications and booming EV market. Focus of research and development is primarily on the cathode material, especially NMC & NCA. [115].

Currently, PHS is the prominent storage system in Sweden. It caters to grid-balancing needs over varied timescales. Hence, the need for BESS is very limited and its development hinges on the evolution of electricity system and market in the future. Existing policy framework provides subsidies to individuals for the installation of storage systems. Owners of grid-connected storage units are obliged to pay grid tariffs, feed-in-tariffs and taxes for the electricity supplied by the grid. However, Storage units with capacities lower than 1500 kW are exempted from paying feed-in-tariff. [105]. A study conducted for the Swedish residential sector shows that the investment in BESS integrated with solar PV installations add value mainly in case of high self-consumption & market arbitrage. [116]. Grid-scale BESS is still at the inceptive phase in Sweden but is slowly gaining interest. The current facility operated by Fortum is built in conjunction with hydropower plant located at Borlänge. The Li-ion based system has a storage capacity of 6.2 MWh and power output of 5 MW. [117]. In 2022, Ellevio, a Swedish electricity enterprise commissioned Alfen, a Netherlands based smart energy company, to install 11.9 MWh BESS with a power output of 10MW. Upon completion, this installation in Grums will provide balancing services – fast frequency reserve (FFR) with a response time < 0.7 seconds. Another BESS project in progress is a 5 MW power output, 20 MWh facility in Uppsala by Vattenfall. [118].

4.3 EnergyPLAN

This chapter provides a brief overview of existing energy system modelling tools, describes different features of EnergyPLAN modelling tool and its applications in the literature.

Energy transition is an enormous challenge and hence, the policy makers require clear-sighted advice to make informed decisions. In this regard, Energy System Models (ESM) serve as guiding instruments and offer insights into current & future energy systems. [20]. Barnett presented the first structured ESM in 1950. Since then, the advancement in computer science has aided the development of a variety of ESM models.

Decarbonization strategies at the national level require notable changes to the energy infrastructure [21]. Therefore, the interaction between different sectors & energy carriers is considered as a crucial element in the energy systems of the future [22]. Thus, an ESM applied at the national level must accommodate climate goals, different sectors and their interconnection in the model [21].

4.3.1 Modelling Tools

The choice of an ESM in a study depends on its research objectives & scope. [23] reviewed 37 ESMs that are widely used in the analysis of RES integration. Table 9 shows characteristics of some of the ESMs across the spectrum.

Table 9: Characteristics of Energy System Modelling Tools [23], 73)

Energy System Model	Geographical Scale	Maximum Timeframe	Temporal resolution	Availability
TRNSYS16	Community	1+ years	Seconds	Commercial
HOMER	Community	1 year	Minutes	Commercial

H2RES	Island	No Limit	Hours	Internal use
EnergyPLAN	National	1 year	Hours	Free
SIVAEL				Free
STREAM				Free
Mesap PlaNet	National	No limit	Minutes	Commercial
MARKAL/TIMES	National	50 years	Hours/days/months	Commercial
LEAP	National	No limit	years	Commercial
OSEMoSYS	National	No limit	Flexible time slice	Free
SimREN	National	No limit	Minutes	Not Free
RETScreen	User-defined	50 years	Months	Free
BALMOREL	International	50 years	Hours	Free
MESSAGE	Global	50+ years	5 years	Simulators are not free

Apart from the tools listed in table 9, ESMs such as HYDROGEMS, energyPRO, COMPOSE etc. are used at project levels. For example, HYDROGEMS is used to simulate hydrogen-based RES stand-alone systems. EnergyPLAN, Mesap PlaNet, SimREN & LEAP are the ESMs suitable to simulate 100% RES systems. However, if the objective of the study is to understand the fluctuations in energy system due to VRES, the former three are more suitable as they have hourly resolution compared to the latter (LEAP) that has yearly resolution. [23].

The conditions required to conduct this thesis work include:

- Provision to simulate 100% RES based future energy system of Sweden
- Fine temporal resolution (days or hours)
- Provision to include major sectors within the energy system – electricity, industry, transport & heat (Cross-sector approach)
- Provision to add storage technologies to facilitate PtH2 & PtH
- Open-source or free to download modelling tool
- ESM that has been extensively used to model energy systems at the national level

Considering all these requirements, the thesis was conducted using EnergyPLAN ESM tool. Features & advantages of EnergyPLAN are discussed in the following section.

4.3.2 EnergyPLAN – Advanced Energy system analysis computer model

EnergyPLAN, is an 'Advanced energy system analysis computer model' [119]. It was developed by Henrik Lund at Aalborg University, Denmark in 1999. Since then, the model has been continuously updated and the latest version is 16.1. The primary objective of EnergyPLAN tool is to assist in formulating national / regional energy strategies. It facilitates the analysis of technical, economical & environmental impact of these strategies. As a simulation tool, it allows the user to devise a variety of energy systems in order to compare various parameters. Therefore, EnergyPLAN is not necessarily an optimization tool, but rather a simulation tool that presents different configurations for an energy system. Some of the key features of EnergyPLAN are as follows [53]:

- It is a deterministic model. Therefore, the tool simulates energy system defined by the user. The results always depend on the input parameters & values defined by the user.
- The timeframe of the analysis is one leap-year (8784 hours) with a time-step of 1 hour. Further, the model serves as an end-point of an energy system in the transition pathway, rather than as a starting point.
- Different systems within the model are aggregated at a regional or national level. For example, the district heating system of a country is defined in three groups.

The model optimizes the operation of a given energy system for a period of 1 year.It takes very less computational time (few seconds to minutes), as the model is based on analytical programming instead of iterations or advanced mathematical tools.Figure 23 shows the schematic diagram of EnergyPLAN computer model, version 16.1. As depicted in the figure, the model enables the simulation of an entire energy system containing electricity, heat, transport & industrial sectors, thermal, nuclear, hydroelectric & VRES power plants, various storage technologies and associated costs. [23].

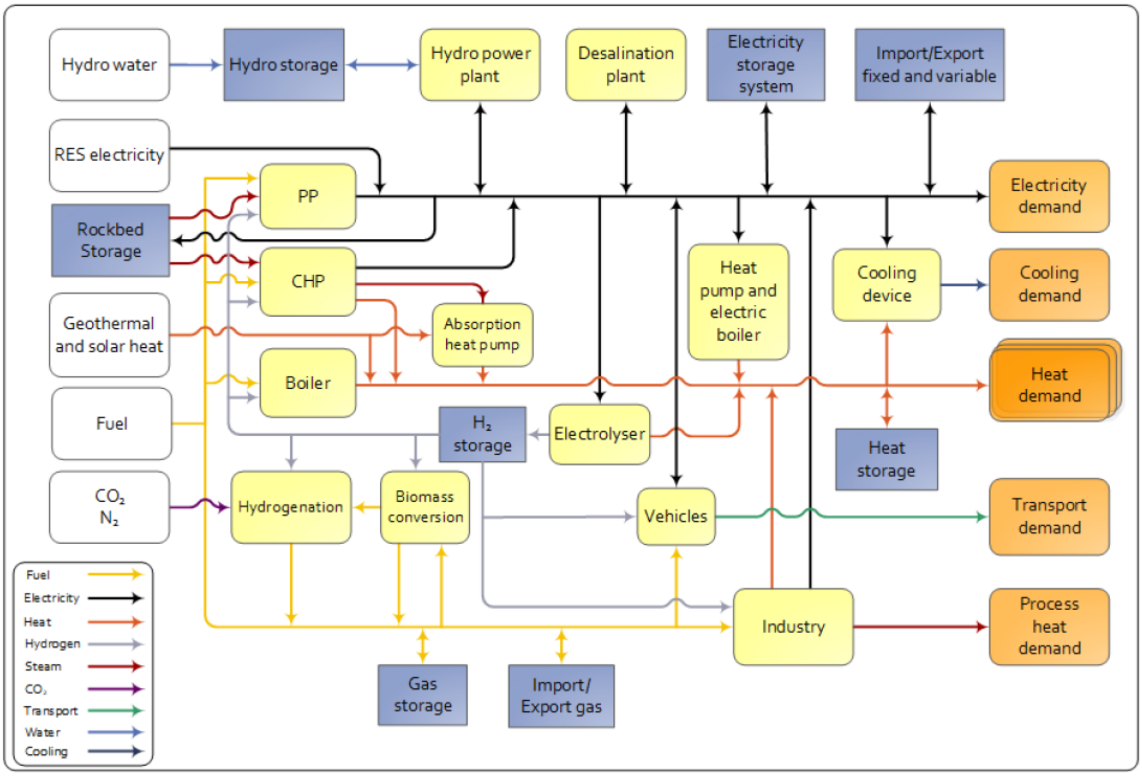


Figure 23: Schematic representation of EnergyPLAN v16.1 ESM [120]

The model consists of a Graphical User Interface (GUI) wherein the user can enter or select values for various input parameters or upload hourly input distribution files. Following are the general computational steps. [54].

1. Calculation from the input tab sheets.
2. Initial calculations excluding electricity balance.

3. Run the simulation based on the choice of simulation strategy – Technical simulation or Market Economic Simulation.
4. Compute output parameters – CEEP, Fuel total, Cost calculations, CO_2 etc.

Input parameters of the model are as follows [120]:

1. Energy demands - Electricity, heat, transport & industry
2. Energy supply sources, conversion technologies & fuel distribution – Wind, Solar PV, Nuclear Energy, Hydropower, CHP, biogas, gasification plants, hydrogenation units, boilers & heat pumps.
3. Storage Technologies – Electricity storage, hydrogen storage, gas storage, TES, V2G
4. Costs – Capital costs, fuel costs, fixed and variable O&M costs, taxes & external electricity market prices.
5. Choice of Simulation Strategy

EnergyPLAN offers two types of simulation strategies [120]:

- Technical Simulation: In this case, the model identifies the least fuel consuming solution for a given set of inputs in order to minimize the import / export of electricity and balance heat demand [120], [54].
- Market-Economic Simulation: The model seeks to identify the least cost solution for a given energy system based on the assumption that all the plants must obtain optimal profits. This strategy uses a market model similar to the Nordpool market. Therefore, it focuses on minimizing the short-term electricity & district-heating costs. [120], [54].

The output of the simulation consists of energy balance, annual production from different power plants, import / export / excess production of electricity, fuel consumption and total system costs. The results can also be generated with a time-step of one hour to analyse the behaviour of different technologies in various seasons or time periods of the year. Ref (67).

The context and overview in this chapter serves as a preamble for the next phase of this study. The next chapter will explain the methodology of this study, including the detailed description of scenarios, model inputs, simulation strategies employed in EnergyPLAN and relevant considerations and assumptions.

5. Methodology

This chapter focuses on the steps and processes incorporated in this thesis to determine the answers to the research questions stated in Chapter 3.

An overview of the methodology with the steps and its sequence is shown in figure 24. Preliminary tasks included studying different sectors within the Swedish energy system, long-term targets, VRES integration and storage technologies. It was followed by a review of the current literature & energy system models. This context and background are covered in chapters 2 and 4 of this report. Data required for simulations was synthesized from various articles, reports & statistics published by relevant agencies and scientific publications.

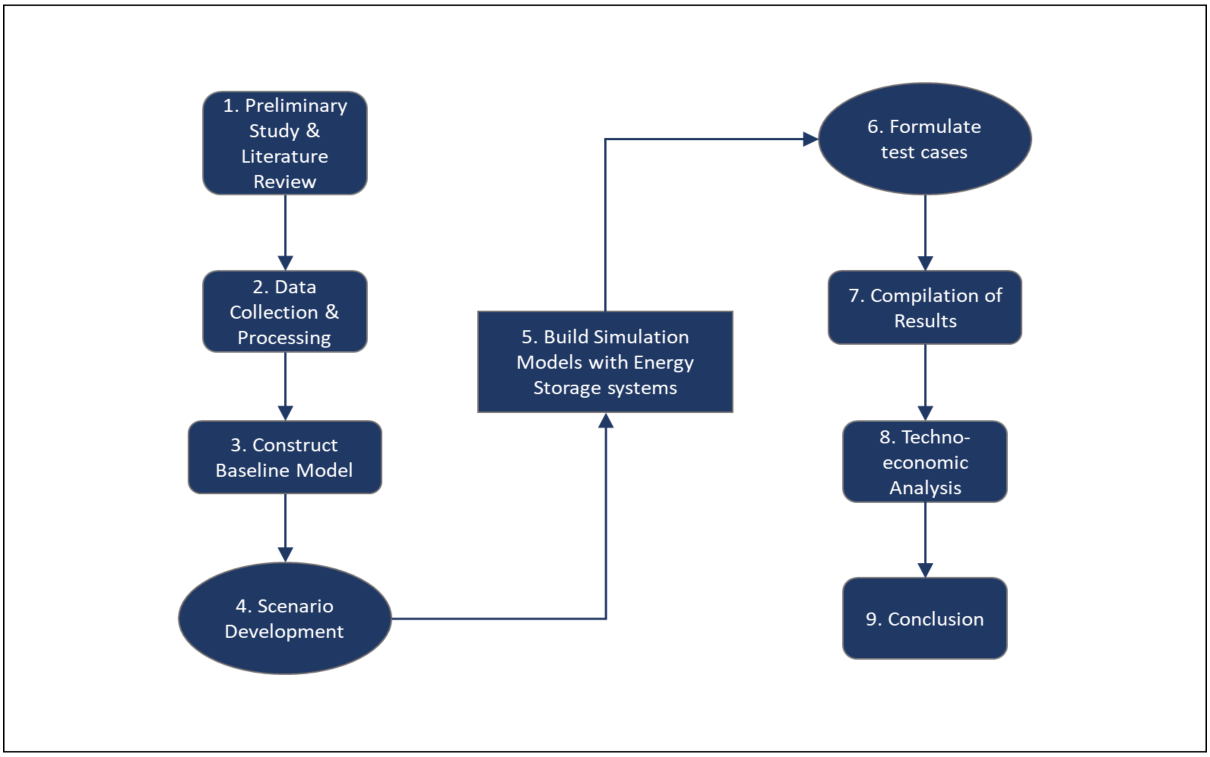


Figure 24: Steps in the methodology

The choice of ESM was based on the research questions in the context of cross-sector approach that encapsulates electricity, district heating, transport and industrial sectors. The aim was to configure and simulate a comprehensive fossil-free energy system of the future based on daily or hourly balance of demand and supply. The ESM was also required to have the provision to incorporate PtH and PtH_2 strategies and offer different storage options. In addition, it was also important to have a deterministic model to evaluate the impact of storage for varying VRES inputs. Finally, the model had to be an open source or free-to-download tool. Thus, taking into account all of these requirements, EnergyPLAN application was employed two configure two different scenarios. Features of EnergyPLAN modelling tool is described in Chapter 4.3.2 Advanced Energy system analysis computer model.

As elucidated in chapter 4.3, EnergyPLAN is a modelling application with a comprehensive ESM as shown in figure 25. It facilitates the design & analysis of RES-based energy systems. It is a freeware programmed in Delphi Pascal and the tool can be downloaded from www.energyplan.eu. [54].

It is a deterministic model i.e.; the application simulates a user-defined energy system at regional or national scale and produces outputs depending on the set of inputs & a pre-defined analytical program. [54]. Thus, it neither predicts the future of an energy system nor an optimal configuration but provides multiple transition alternatives for comparison & analysis. This characteristic is especially beneficial in long-term projections due to high uncertainties in the evolution of demand, supply, technology, markets & policies. [120], 67).

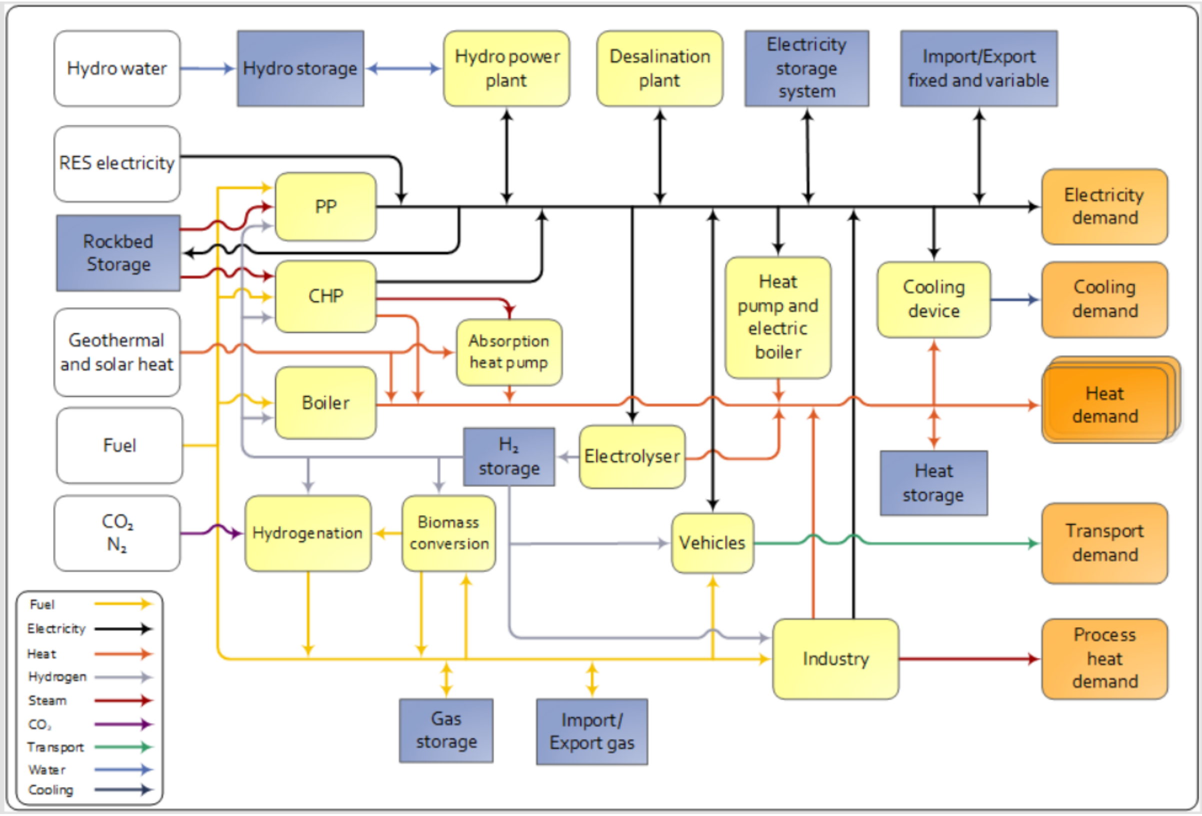


Figure 25: EnergyPLAN Energy System Model (version 16.1)

It enables the user to incorporate both well-established & unconventional technologies into the model. For instance, the model has provisions to include wave power, tidal power, CSP, biomass gasification, hydrogen, Vehicle-to-Grid (V2G) etc., along with hydropower, nuclear power, wind power, Solar PV, district heating and TES. [54].

As mentioned in Chapter 2, EnergyPLAN has been extensively used in the studies focused on transition strategies and in research to ascertain the role of different components of an energy system such as storage, V2G, VRES integration, heat pumps, flexible demands and so on. [54]. Figure 26 shows the computational process in EnergyPLAN. Table 10 shows different input tabs in EnergyPLAN considered for this study.

Table 10: Input tab sheets in EnergyPLAN

Demand	**Supply**	**Balancing & Storage**	**Cost**
1. Electricity 2. Heating 3. Cooling 4. Industry & Fuel 5. Transport	1. Heat & Electricity 2. Central Power Production (CPP) 3. VRES 4. Heat Only 5. Fuel Distribution 6. Waste 7. Liquid & Gas Fuels – Biofuels, Biogas, Hydrogen	1. Electricity 2. Thermal Storage 3. Liquid & Gas Fuels	1. General 2. Investment & Fixed OM – Heat & Electricity, Renewable Energy, Liquid & Gas Fuels, Heat infrastructure 3. Fuel 4. Variable OM 5. External Electricity Market

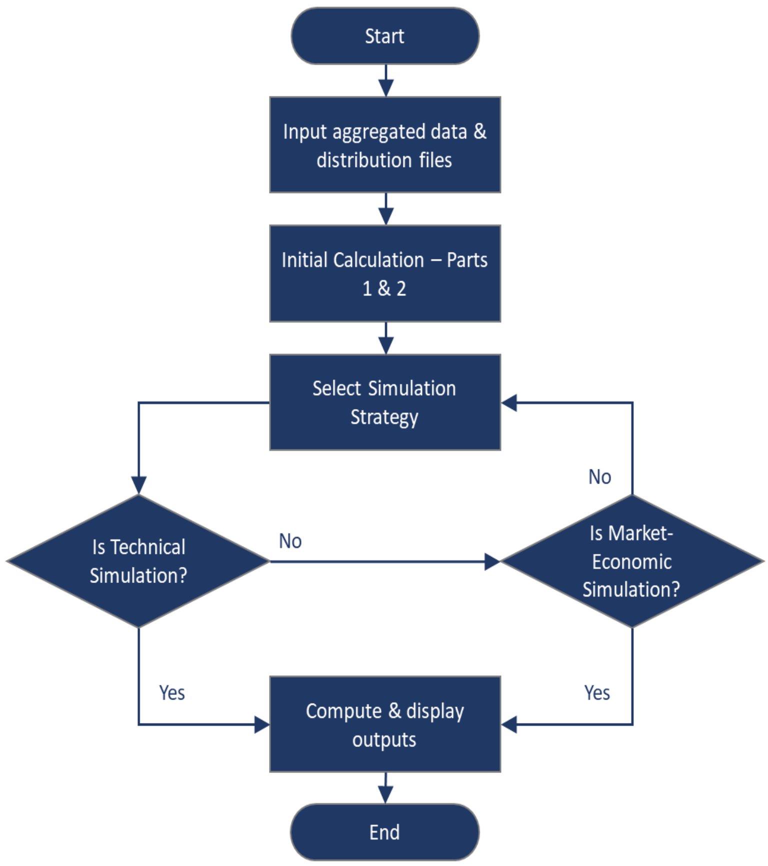


Figure 26: Process flow for the analysis of energy system in EnergyPLAN

Step-1: The first step is to add aggregated numerical values as inputs to various parameters & wherever necessary, corresponding distribution files. The timeframe considered in the simulation is one leap year. For example, if the annual electricity demand of a country is 140 TWh, the value entered in section 'Electricity' under 'Demand' tab is 140. Corresponding distribution file containing hourly electricity demand in 8784 rows and 1 column is uploaded as a .txt file. Similarly, input data is added in other tabs mentioned in table 11.

Step-2: Initial computation is executed for some parameters as soon as the data is added to the model. For example, when installed capacity, efficiency & hourly distribution of Nuclear Power Plant is loaded in the CPP tab, the tool immediately calculates annual and hourly production. This step has two parts. Initial calculations of parameters in electricity balance are executed in Part 1 and calculations for remaining parameters is covered in part 2.

Table 11: Input components for electricity sector in EnergyPLAN

Component	**Description**
Total Annual demand = Sum of Electricity for • transport • individual electric heating, heat pumps & Cooling • conversion for biomass • fixed import /export • net demand incl. losses	Electricity demand is split into different aggregated inputs as shown. Net demand is the demand from remaining sectors. Hourly distribution files are uploaded for net demand, transport, and fixed import / export. Net hourly electricity demand is then estimated based on these individual inputs.
Total Supply = Sum of production from • Hydropower • Nuclear power • CHP (electric) • Other Thermal Power Plants • VRES – Solar PV & Wind	Inputs required to compute production from each technology are: 1. Installed Capacity, for all power plants. 2. Efficiency, for hydro, nuclear, thermal & CHP 3. Reservoir & pump capacity, for hydropower 4. Hourly distribution files for all technologies except CHP & thermal PP, as production from these plants are computed during simulation. 5. For VRES, production is estimated based on hourly distribution & installed capacity. Therefore, in some cases, a correction factor can be added to rectify the capacity factor and hence, total production.
External Transmission Line (ETL) Capacity, import & export	1. Maximum transmission line capacity for international connections is specified in MW. 2. External wish for import & export can be uploaded as an hourly distribution file. The model then computes total request for import & export.
Balancing & Storage – This tab consists of • Grid stabilization & CEEP Regulations • Storage **Note:** CEEP is the Critical Excess Electricity Production. For example, if the excess production in an hour is 11,000 MW and the max. capacity of ETL is 10,350 MW, then CEEP = 650 MW.	1. Requirements for grid stabilization can be specified here. Some examples include minimum production from CHP, PP etc. 2. CEEP is detrimental to the operation of power system & hence, options to prevent CEEP can be selected in this tab under CEEP regulations. 3. Electricity Storage can be specified in terms of charging, discharging & storage capacities and corresponding efficiencies.

Table 12: Input components for heating sector & fuel distribution in EnergyPLAN

Component	**Description**
Demand – Individual Heating (IH) is split into • Boilers – Coal, Oil, NG & Biomass • Electric heating • Heat Pumps	Heating demand is branched into individual demand & DH demand. IH demand for each type of fuel is specified along with corresponding boiler efficiencies. Electric heating demand mentioned here is subtracted from the gross electricity demand in 'Electricity' tab sheet mentioned in table 11.
Demand – District Heating (DH) is divided into • Group 1 – Heat only plants (no-CHP) • Group 2 – Small CHP plants • Group 3 – Large CHP plants	Demand (incl. network losses) is specified separately for each group, along with corresponding % of network loss. The model then computes net heat demand in each group. Distribution file is required for both IH & DH demands.
Cooling demand has following components – • Individual Cooling (IC) demand • District Cooling (DC) demand	IC signifies electricity required for cooling. Like DH, DC is also split into 3 groups. It comprises of natural & absorption cooling. Heat for absorption cooling is supplied by DH systems. Cooling demand, COP & network losses are specified in the input tab. Distribution files are required for both cooling demand & natural cooling.
Supply - District Heating (DH) systems • CHP – Available in Groups 2 & 3 • Thermal Boilers – All three groups • Heat Pumps – G2 & G3 • Excess heat – All 3 groups • Energy from Waste – All 3 groups • Electrolysers – G2 & G3	DH group 1 is built to fulfil heat demand only, via boilers, excess or waste heat delivered to DH network, energy from waste input & residual energy from electrolysers. In addition to these systems, DH groups 2 & 3 also have CHP and heat pumps. However, only CHPs in group 3 can operate in condensing mode as they are associated with large heat sink. Waste input is specified in 'waste' tab, along with efficiencies to generate heat & electricity in all 3 DH groups. Hydrogen produced by electrolyser goes to H_2 storage & heat generated in the process is fed into DH network. Electrolyser capacity & corresponding efficiencies are specified in 'hydrogen' tab.
Thermal Energy Storage (TES) – Groups 2 & 3	TES capacity can be added for DH groups 2 & 3.
Fuel Distribution (FD) – It is the fuel input ratio of Coal: Oil: Natural Gas: Biomass (fixed or variable). Hydrogen & Electro-fuels are added as absolute or fixed values. FD is specified for – • DH Group 1 • Boilers and CHP (heat) in G2 & G3 • PP G1 (Condensing PPs + CHP G3) • PP G2 (Only Condensing PPs)	Example – If FD ratio in DH G1 is 1:2:3:4, • If 'fixed' is selected, DH G1 produces fixed amount of heat. (1+2+3+4 = 10 TWh). • If 'variable' is selected, heat produced by DH G1 varies, but the contribution from each fuel follows this ratio. Thus, if production is 8 TWh, then consumption of coal = 0.8 TWh, oil = 1.6 TWh, NG = 2.4 TWh & biomass = 3.2 TWh.

Table 13: Input components for transport & industry in EnergyPLAN

Component	Description
Transport demand is divided as follows - • Jet Fuel • Diesel • Petrol • NG • Biofuels – JP, Diesel & Petrol • Hydrogen, Electrofuels • Electricity (Dump & Smart Charge)	Demand for individual fuel is specified in transport tab. Distribution files are required for hydrogen demand, electricity dump charge & electricity smart charge. In case of smart charge, additional inputs are required to configure Vehicle-to-grid (V2G) capacity. The model computes total km/year based on aggregated fuel demand (TWh) and km/kWh for corresponding fuels.
Industry demand is split into - • Coal • Oil • Natural Gas • Biomass • Hydrogen	Industry tab contains three columns – 1. Industry – Demand for each fuel is specified here. 2. Various – Consumption of fuels unaccounted elsewhere can be added here. For example, agriculture, forestry, commercial services etc. 3. Fuel losses – It is added as % of energy from the fuel that is lost due to losses in production facilities such as refineries, own-use in energy sector, transmission & distribution losses. 4. A distribution file is required for Natural Gas.

Input parameters in demand & supply tabs for different sectors are described in tables 11, 12 & 13. Although additional input tabs can be added to the configuration (as seen in table XX), this discussion focuses only on the parameters considered for this thesis.

Step-3: After adding inputs & distribution files (Step – 1), the application immediately performs initial computations (Step – 2). Then, the required simulation strategy is selected under 'Simulation' tab to run the model. EnergyPLAN has two main simulation strategies – Technical simulation & Market Economic Simulation. The output of simulation for same set of inputs can vary depending on the choice of the simulation strategy.

Technical Simulation – Under this strategy, the model aims to determine overall energy balance by utilizing least fuel consuming technologies & by minimizing export & import of electricity. Thus, cost is not a criteria & technical input data is enough to run the simulation. It is further divided into two types –

- <u>Balancing heat demands</u>: In this strategy, production from CHP & heat pumps in DH groups 2 & 3 are mainly driven by the heat demand. The model seeks to establish balance between heat demand & supply every hour. The demand at any given hour in DH groups 2 & 3 are fulfilled by various heat producing systems attached to these groups in the following sequence.[2]

[2] Heat from Solar Thermal Systems (STS) precede excess heat. But it is not mentioned here, since STS is not considered in any of the test cases developed for this thesis.

1. Excess heat = Waste heat from industry + heat from waste input + heat from biomass conversion units + residual heat from electrolysers
2. Heat from CHP 2 & 3 (Within the specified max. MW_{th} limit)
3. Heat pumps (Within the specified max. MW_{th} limit) and
4. Thermal Boilers

- Balancing both heat & electricity demands: In this strategy, the model aims to minimize hourly export, unless external import / export demand is specified in CPP tab. At any given hour, the excess electricity is utilised by heat pumps in DH network. This increases the overall electricity demand and simultaneously decreases the need for both heat & electricity production from CHP. In such a case, the excess heat production from CHP is fed to heat storage, while excess electricity reduces the production from other condensing power plants.[3]

Market-Economic Simulation – Unlike technical simulation, the model aims to determine least-cost solution to balance the demand & supply instead of least fuel consuming technology. Therefore, along with technical input data, cost data comprising of investment costs, fuel costs, fixed & variable O&M, CO_2 price, taxes and hourly electricity price in external market is required to run the simulation. Production from different PPs is determined such that the cost of production becomes equal to marginal cost. This strategy resembles the Nordpool market and hence, focuses on optimization of supply-side of a given energy system, based on short-term costs.

Figures 27 & 28 show the steps involved in technical and market-economic strategies respectively.

Step-4: The application runs the simulation. EnergyPLAN provides multiple choices to display the output – display on the screen, copy to clipboard, print as pdf and so on. The output parameters are:

- Heat production from boilers in DH groups.
- Import, Export & CEEP (depending on specified CEEP regulation, grid stabilization regulations, electricity storage).
- Heat & Electricity Production from CHP (DH Groups 2 & 3), and heat balance based on the production from the other systems & TES.
- Electricity production from condensing power plants.
- Total fuel consumption by all sectors & energy balance of the system
- CO_2 emissions based on CO_2 content in different fuels & CCS specifications.[4]
- Share of Renewable Energy
- Annual Costs and Import / export in gas grid

[3] Priority to balance electricity can also be specified as a sequence of numbers under technical simulation. It consists of three methods – 1. Pumped hydro, 2. V2G & 3. Rock bed storage. Since 2 & 3 are not considered in this work, the default sequence of 123 is used for all scenarios.

[4] Carbon Capture & Storage is not added to the energy systems developed in this work, since it is beyond the scope of this thesis.

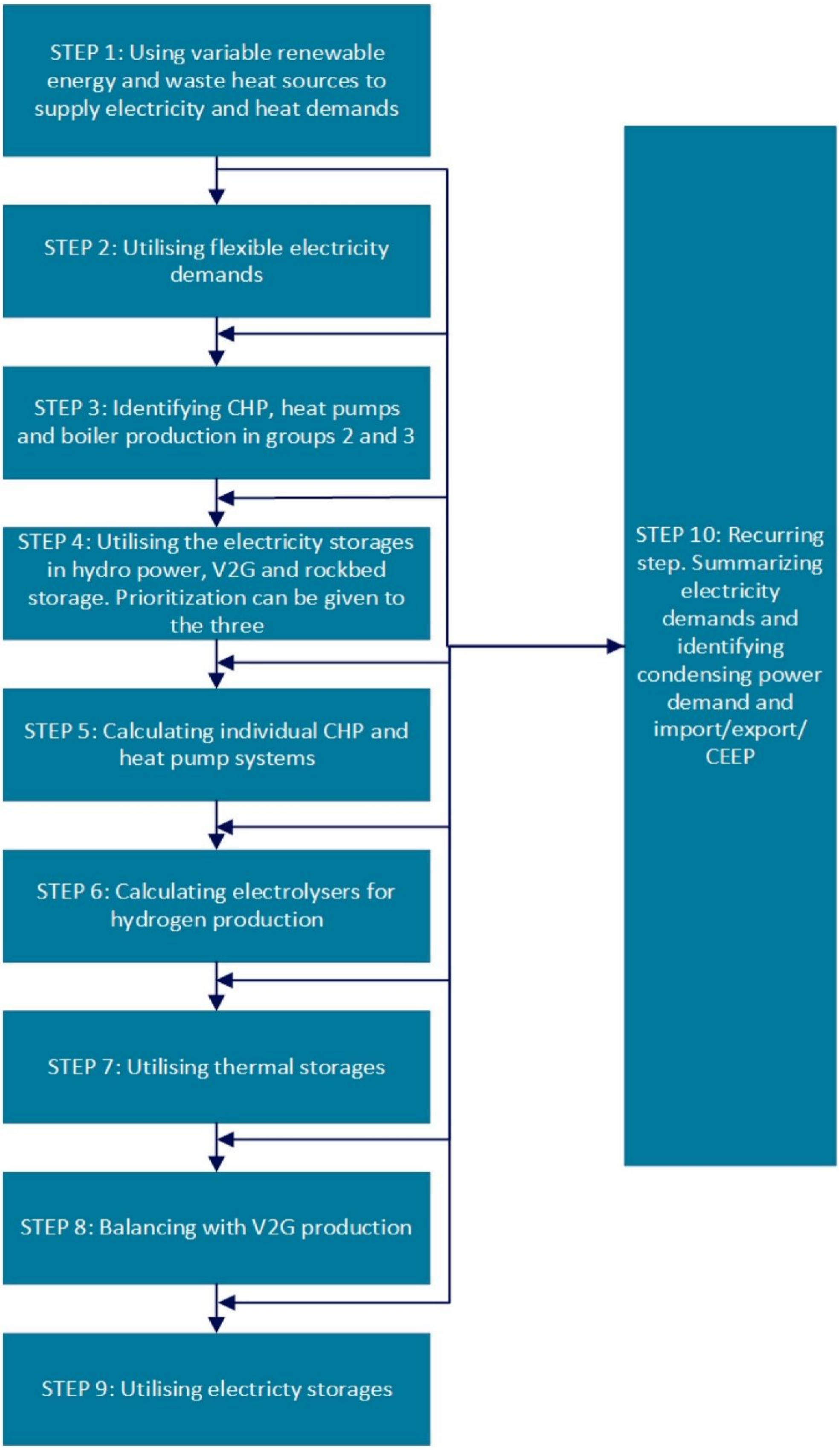


Figure 27: Technical Simulation Strategy for balancing H&ED in EnergyPLAN [54]

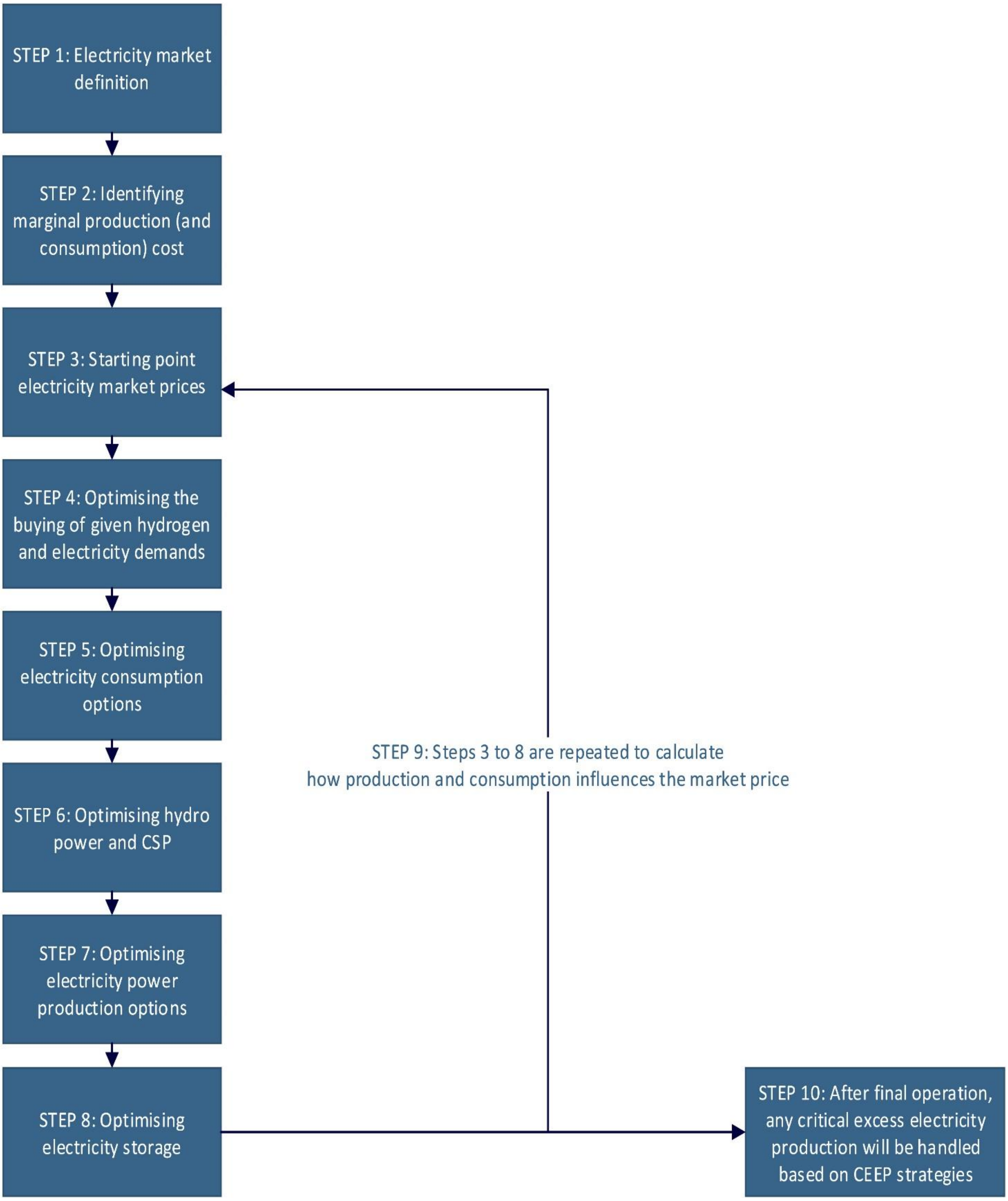


Figure 28: Market-Economic Simulation Strategy in EnergyPLAN [54]

5.1 Formulation of Scenarios

Prior to configuring future scenarios, a baseline or reference model was configured in EnergyPLAN for the Swedish energy system in 2019, which is discussed in detail in Chapter 4. Choice of 2019 as reference year was mainly driven by two factors – availability of relevant energy statistics and the system characteristics in a pre-pandemic timeframe. The aggregated inputs to the model such as electricity, heating, industry & transport demands, production from hydropower, nuclear, wind power plants etc. were derived from the statistics published by different agencies (Energimyndigheten, Svenska kraftnät). Model inputs & components of the reference model developed in EnergyPLAN are summarized in table 14. Description of all inputs, distribution files and corresponding references are tabulated in Appendix A.

Table 14: Summary of characteristics of the Swedish Energy System ref. model (2019) in EnergyPLAN

Model Inputs & Features	**Description**
Reference Year / Region	2019 / Sweden
Electricity Demand	Net demand + Electric Heating + Electricity for Transport
Electricity Supply	Nuclear PP, Hydropower, VRES (Wind & Solar), CHP & Condensing PPs
Import / Export	ETL Capacity & external wish for import / export
Heating & Cooling Demand	IH = Oil, NG, Biomass boilers, Electric Heating; DH = G1 (Heat only plants) + G3 (CHP + Others); DC demand in G3
Heating Supply & TES.	Boilers in G1 & G3, CHP & HP in G3, Excess heat in G1 & G3, Energy from Waste in G1 & G3, TES in G3
Transport Demand	Jet Fuel, Diesel, Petrol, NG, Biofuel & Electricity
Industry Demand	Coal, Oil, NG & Biomass
Distribution Files - Time-Period & Time-Step	8784 hours with 1 hour time-step
Simulation Strategy	Technical Simulation – Balancing both heat & Electricity demands

- Distribution files for electricity demand & supply was constructed based on the hourly data of 2019, published by the Svenska kraftnät – the Swedish TSO.
- In case of IH & DH hourly distribution of heat-demand was calculated based on Heat Degree Day (HDD) method as shown in table 15. To maintain seasonal balance of heat demand & supply, same distribution file was used for hourly production of excess heat & waste from energy. Sweden has extremely low district cooling demand (1.098 TWh) compared to district heating demand (57.33 TWh) [57]. Therefore, DC demand was added in Group 3 and corresponding hourly distribution was calculated based on Cold Degree Day (CDD) method as shown in table 15.
- Hourly distribution files from EnergyPLAN distribution library were used for industry (gas-grid hourly balance) & transport sector (hourly distribution of electricity for transport).

Table 15: Equations to determine hourly load distribution in district heating & district cooling

Eqn. no.	Equation	Description
3	$D_h = D_{rsh} + D_{inh} + D_{lh} \quad TWh$	D_h = Annual DH demand; D_{rsh} = Heat demand from residential & services sector; D_{inh} = Demand from industries; D_{lh} = Total Distribution losses; [17]
4	$D_{rsh} = D_{sh} + D_{dhw} \quad TWh$	D_{sh} = Demand for Space heating; Ddhw = Demand for domestic hot water (DHW); D_{sh} = 33% of D_{rsh}. [134]
5	$D_{nh} = D_h - D_{dhw} \quad TWh$	D_{nh} = DH demand without DHW
6	$hdh_{1,i} = \begin{cases} t_{b,i} - t_{a,i}, & t_{a,i} < t_{b,i} \\ 0, & t_{a,i} \geq t_{b,i} \end{cases}$	h_{dh} = heat degree hour; t_b = base temperature (17°c) [56]; t_a = mean outdoor temperature [132]; at hour i
7	$d_{nh,i} = \frac{D_{nh} * hdh_{1,i}}{\sum_{i=1}^{8784} hdh_{1,i}} \; MWh$	d_{nh} = DH demand (without DHW) at hour i, where i varies from 1 to 8784.
8	$hdh_{2,i} = t_{hw,i} - t_{a,i}$	t_{hw} = avg. temp. of DHW (55°C) [133]
9	$d_{dhw,i} = \frac{D_{dhw} * hdh_{2,i}}{\sum_{i=1}^{8784} hdh_{2,i}} \; MWh$	d_{dhw} = DHW demand at hour i
10	$d_{h,i} = d_{nh,i} + d_{dhw,i}$	d_h = total DH demand at hour i
11	$cdh_i = \begin{cases} t_{a,i} - t_{b,i}, & t_{b,i} < t_{a,i} \\ 0, & t_{b,i} \geq t_{a,i} \end{cases}$	cdh = cold degree hour at hour i.
12	$d_{c,i} = \frac{D_c * cdh_i}{\sum_{i=1}^{8784} cdh_i} \; MWh$	d_c = total DC demand at hour i

Reference Model Validation - After uploading all inputs of 2019 in EnergyPLAN, the application was run to compare the values of different fuels against the actual values in the statistics published by Energimyndigheten, as shown in Table 16.

Table 16: Parameters pertaining to reference model validation for the base year 2019

Parameter	Actual Values (TWh) [17]	Model in EnergyPLAN (TWh)
Coal	19.298	19.14
Oil	114.1336	114.04
Natural Gas	11.335	11.13
Biomass[5]	116.557	115.54
Nuclear Fuel input	180.945	180.92
Hydropower	65.29	65.3
Wind power	19.846	19.85
Solar power	0.663	0.66
% RES share (Electricity)[6]	51.86 %	52.6 %
Overall Energy Balance	548.44	548.07

[5] Biomass supply in Ref 7 includes municipal bio-waste, while it is added separately as municipal solid waste (MSW) under waste input section in EnergyPLAN. Therefore, Net Biomass in Ref 7 = Gross Supply (excl. biofuel) – (Municipal bio-waste) = 116.178 TWh; Net Biomass in EnergyPLAN = Gross Supply (excl. biofuel) – waste input = 137.01 – 21.47 = 115.57 TWh.

[6] % RES share in electricity = ∑ (Hydro-electricity + wind power + Solar PV)*100 / Gross electricity production

With the reference model validation as preamble, the next step was to formulate scenarios to envisage the future energy system of Sweden in 2045. In this regard, two scenarios – SWE_2045 & NFF_2045 were formulated to configure two types of energy system in 2045. The main distinguishing features of these scenarios are as follows –

1. SWE_2045 (Sweden 2045) – The underlying principle of this scenario is based on the EU Reference Scenario developed by Energimyndigheten [56].

- Fossil fuels still cater to energy demand from transport & industrial sectors, although its share is considerably lesser than the share in 2019.
- Electricity demand in transport & industrial sectors is higher than the levels in 2019 due to increased electrification.

2. NFF_2045 (No Fossil Fuels 2045) – In this scenario, all sectors are completely decarbonized such that fossil fuels are not part of the energy mix.

- Energy demand from industry is fulfilled by electricity, biomass & hydrogen, while biofuels & electricity cater to transport demand.
- Electricity demand is significantly higher than that of SWE_2045 due to increased electrification of transport & industrial sectors and demand for production of electrolytic hydrogen.

Common features in both the scenarios are listed below –

1. Nuclear energy is still part of the electricity supply mix, but production is lower than in 2019.
2. Increase in total electricity demand due to increased electrification of all sectors.
3. Significant increase in electricity production from VRES - onshore & offshore wind power and solar PV compared to 2019 [56], [51] [17].
4. Installed capacity & production from hydro power remains at current levels.
5. Residential & Services sector is fossil free. Individual heat demands are fulfilled by heat pumps and biomass. There is only marginal increase in DH demand compared to current levels. [56].
6. Increased utilization of heat pumps in both DH & IH [56].
7. Increase in the overall contribution of bioenergy [56]. CHP & Thermal Boilers are operated only by biomass in NFF_2045.
8. Hydrogen produced via electrolysis plays a key role in NFF_2045 mainly due to the implementation of HYBRIT, wherein coal-based blast furnace in steel industry is replaced by HDRI process [98], [51] [17].
9. Reduction in demand for fossil fuels in transport sector is mainly driven by electricity & biofuels [56].
10. Cost of coal, oil and natural gas are considerably higher than 2019 levels [130].

Two energy systems were configured in EnergyPLAN to represent these two scenarios. Technical and cost data were derived from various reports & publications in the literature pertaining to long-term scenarios. Estimations based on reasonable assumptions were made for some inputs. All model inputs, corresponding references & assumptions are listed in Appendix A.2 to A.4. Table 17 illustrates the key differences in these scenarios.

Table 17: Comparison of key inputs to different energy system models in EnergyPLAN

Parameter	**2019**	**SWE_2045**	**NFF_2045**
Net Electricity Demand[7] (TWh)	136.4	147.5	196.6
CHP & CPP Fuel Input	Coal: Oil: NG: Biomass [8]	Coal: Oil: NG: Biomass	Only Biomass
Hydropower (TWh)	65.3	68	68
Nuclear power (TWh)	66.2	28	28
Wind power (TWh)	19.84	171.2	251.4
Solar PV (TWh)	0.66	9.7	9.7
ETL Capacity (MW)	10,350	11,950	11,950
IH[9] – Oil (TWh)	0.89	0	0
IH – Natural Gas (TWh)	0.81	0	0
IH – Biomass (TWh)	10.35	10	10
IH – Electric Heating (TWh)	20.9	0	0
IH – Heat Pumps (TWh)	0	22.3	22.3
DH Demand (TWh)	57.6	62.2	62.
DC Demand (TWh)	1.09	1.09	1.09
Industry: Coal	13.11	11.2	0
Industry: Oil	9.16	6.2	0
Industry: Natural Gas	3.9	5.3	0
Industry: Biomass	58.1	53.3	93
Industry: Hydrogen	0	0	45
Industry: Electricity	48.3	58	96
Transport: Jet Fuel	1.8	1.7	0
Transport: Diesel	38.6	25.1	0
Transport: Petrol	23.15	9.1	0
Transport: Natural Gas	0.28	0.3	0
Transport: Biofuels	16.58	9.1	18.5
Transport: Electricity	2.9	17	28.9

The aggregated model inputs shown in table 17 shows the demand and installed capacities in various sectors for both the scenarios in 2045, were derived from the studies on long term scenarios published by various agencies listed in the references in Appendix A.2 to A.5. In SWE_2045, the demand in the transport and industrial sectors was extrapolated based on the EU reference scenario published by Energimyndigheten, wherein fossil fuels are still part of the energy mix, but their share is considerably lower than in 2019 [56]. The demand in NFF_2045 was based on the consideration of replacing all fossil fuels in DH, transport, and industry with biomass, electricity, and hydrogen (in the industry). The electricity for transport demand was estimated based on average km/kWh available in EnergyPLAN as shown in

[7] Net electricity demand = Total electricity demand (incl. losses) – IH (Electric heating or Heat Pump or both) – electricity for transport
[8] Fuel Distribution ratio for each model is tabulated in Appendix A.1 to A.4.
[9] IH = Individual Heating demand

Appendix A.3. The increased demand for biomass and hydrogen in the industrial sector was based on a study published by Energiforsk. [98]. Although both solar PV and wind power are anticipated to increase by 2045, this study focuses on additional wind power integration while keeping solar PV as constant input in all test cases. This is because of two considerations - the expansion of wind power is significantly higher than that of solar PV, the growth of PV is mostly limited to the southern part of the country & grid-connected PV systems, due to the irradiance profile in Sweden [74].

Modelling of hydrogen storage & TES in EnergyPLAN are shown in figures 29 & 30. Battery is added as electricity storage in 'electricity balancing & storage tab'. Hydrogen is produced via electrolysis. The capacity of electrolyser is computed by the model based on the demand, Critical Excess Electricity Production (CEEP) and storage capacity. Based on the hourly demand, one fraction of hydrogen is fed to the condensing power plant group to generate electricity while the other fraction caters to the demand in the industrial sector. Heat produced by heat pumps, thermal & electric boilers and CHP plants are utilized to fulfil hourly demand in district heating sector and residual heat is stored in the TES systems.

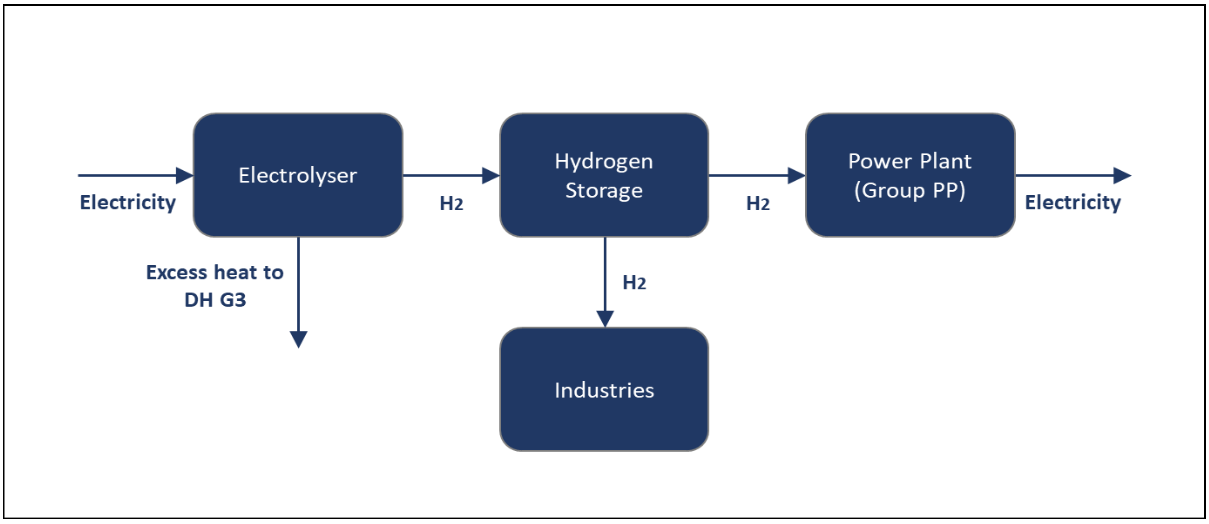


Figure 29: Hydrogen storage in EnergyPLAN for all three Scenarios

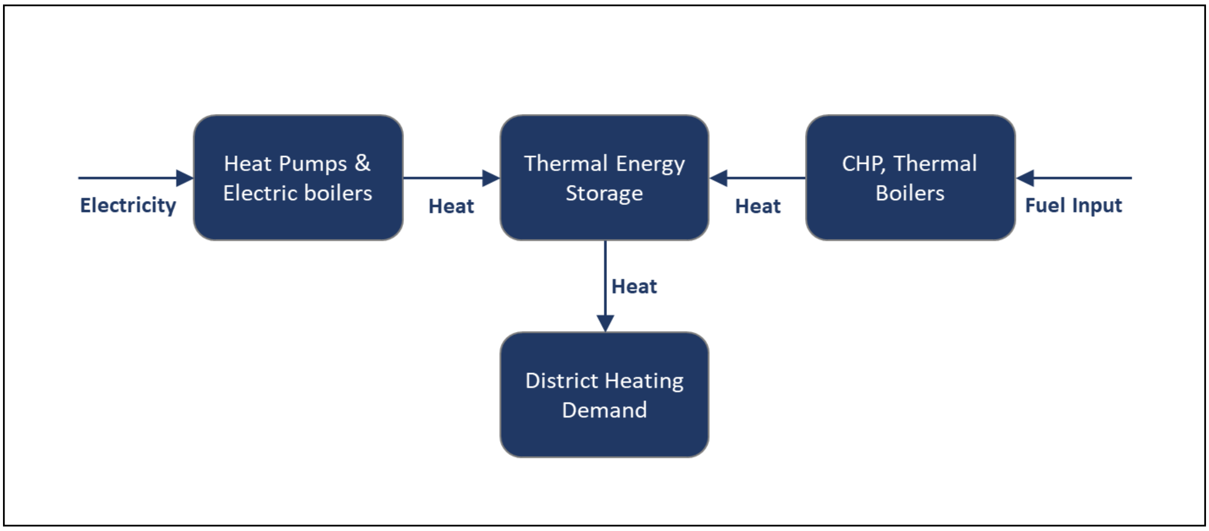


Figure 30: Thermal Energy storage added to DH G3 in EnergyPLAN for all three Scenarios

The range of installed wind capacity (MW) was set to 35 GW to 60 GW for SWE_2045 and 65 GW to 90 GW for NFF_2045 based on demand & supply characteristics in each scenario. Different test cases were formulated for each storage technology. Wind capacity was varied for every test case in order to determine CEEP, total fuel and system costs. In EnergyPLAN, Critical Excess Electricity Production (CEEP) is the residual electricity generated in the system after fulfilling demand & export obligations as shown in equation XX. CEEP is undesirable in a power system, as it impacts the reliability & stability of the system. Total CEEP for a year is the summation of CEEP at each hour.

$$CEEP_i = \sum_{n=1}^{N}(\text{Supplyi}) - \sum_{d=1}^{D}(\text{Demandi}) - Export_i \quad (13)$$

$CEEP_i$: Critical Excess Electricity production in MW at hour i.
Supply: Summation of Electricity generation from N different power plants in MW at hour i.
Demand: Summation of electricity demand from all sectors in MW at hour i.
$Export_i$: International or external export of electricity in MW at hour i. Max. Export = ETL.

% CEEP can be calculated as shown in equation XY. % CEEP less than 5% is considered as the threshold for VRES integration in an energy system. [43]. In this case, VRES integration implies additional wind power integration into the system due to reduction in % CEEP.

$$\%\, CEEP = \frac{\sum_{I=1}^{8784} CEEP_i * 100}{\sum_{i=1}^{8784}\sum_{n=1}^{N} RES_n} \quad (14)$$

$CEEP_i$: Critical Excess Electricity production in a year in TWh.
RES: Annual electricity production by Renewable Energy Sources in TWh

Table 18 shows the test cases T0 – T10 for TES. This set of test cases were simulated in both SWE_2045 & NFF_2045 systems and additional integration of wind power was determined for each case based on the corresponding % CEEP level.

Table 18: Test Cases with different levels of HP & TES capacities.

Case Name	**Heat Pump Capacity (MW_e)**	**TES Capacity (GWh)**
T0	0	0
T1	400	0
T2	800	0
T3	1200	0
T4	400	10
T5	400	20
T6	400	40
T7	600	20
T8	800	30
T9	1000	40
T10	1200	50

Table 19 shows the test cases H1 – H5 for hydrogen storage. This set was simulated in SWE_2045 to evaluate the impact of hydrogen storage in a system without hydrogen demand such that it is anticipated to only facilitate reduction of CEEP. Electrolyser capacity was computed by EnergyPLAN based on demand for 1 TWh of hydrogen in the condensing power plant group, wind capacity input & CEEP.

Table 19: Test Cases with different levels of hydrogen storage capacity in SWE_2045

Case Name	**Hydrogen Storage Capacity (GWh)**
H1	0
H2	10
H3	20
H4	30
H5	40

Table 20 shows the test cases E0 – E3 for battery storage. This set was simulated in SWE_2045 to evaluate the impact of battery storage on CEEP & additional wind integration.

Table 20: Test Cases with different levels of battery storage

Case Name	**Charge / Discharge (MW_e)**	**Storage Capacity (GWh)**
E0	0	0
E1	1000	4
E2	1500	6
E3	2000	8

Table 21 shows the test cases H0 – H10 for hydrogen storage. This set was simulated in NFF_2045 to evaluate the impact of hydrogen storage in a system with significant hydrogen demand (45 TWh) from industrial sector. Electrolyser capacity was computed by EnergyPLAN based on demand, wind capacity input & CEEP.

Table 21: Test Cases with different levels of hydrogen storage in NFF_2045

Case Name	**Hydrogen Storage Capacity (GWh)**
H0	0
H1	10
H2	20
H3	30
H4	40
H5	50
H6	60
H7	70
H8	80
H9	90
H10	100

Table 22 shows the test cases for battery storage in NFF_2045. E0 – E3 signify battery storage, but without hydrogen storage in the system. EH0 – EH3 are test cases where the system has an inherent hydrogen storage of 30 GWh.

Table 22: Test Cases with combination of hydrogen & battery storage in NFF_2045

Case Name	Charge / Discharge (MW_e)	Storage Capacity (GWh)
E0	0	0
E1	1000	4
E2	1500	6
E3	2000	8
EH0	0	0
EH1	1000	4
EH2	1500	6
EH3	2000	8

The total time period of the analysis in EnergyPLAN is one year, with an hourly distribution of 8,784 data points (366 days * 24 hours). Therefore, the simulation results show the impact of storage under various test cases for an annual timeframe in the year 2045.

5.2 Delimitations

The outcome of simulation of an energy system set in the future hinges on underlying assumptions and data referenced from various studies in the literature. In this regard, following are the systemic boundaries.

1. The aggregated inputs in scenarios & test cases are based on long-term studies conducted by Energimyndigheten, Svenska kraftnät and other agencies.
2. The scenarios are modelled at national level and hence, regional constraints pertaining to SE1, SE2, SE3 & SE4 are not incorporated in the simulation. Thus, the output represents systemic behaviour for whole of Sweden.
3. Hourly distribution of electricity is not available for 2045. Hence, it was assumed that the hourly behaviour of demand & supply remains like 2019.
4. Hourly heat demand was modified in accordance with the HDD in 2045. According to RCP2.6 Scenario developed by SMHI, the number of HDD is anticipated to reduce from 5379 (1971-2000) to 4525 in 2045 [131].
5. Alike 2019, the cooling demand is expected to be considerably smaller than heating demand [56]. Therefore, current level of cooling demand is retained for all scenarios.
6. Both CHP and conventional power plants are assumed to be completely flexible.
7. External transmission capacity (ETL) is expected to increase from 10,350 MW (2019) to 11,950 MW by 2027. Data regarding further expansion is not clear. [19]. Therefore, ETL capacity is considered as 11,950 MW in all scenarios.
8. Cost data is common for all scenarios. It is derived from the references mentioned in appendix A.4. Essentially, the cost of fossil fuels and emissions is considered to be higher than current levels in 2045.

The results of the simulation of both the scenarios under various test cases, analysis & inferences are presented in chapter 6.

6. Results & Discussion

In this chapter, results of both the scenarios which were simulated for different storage cases specified in tables 18 to 22 in chapter 5 are discussed.

6.1 SWE_2045

In order to determine CEEP and % CEEP for each storage, SWE_2045 was simulated for varying wind capacities from 35 GW to 60 GW in steps of 5 GW. Figure 31 shows the change in % CEEP for increasing wind capacity inputs under technical simulation strategy.

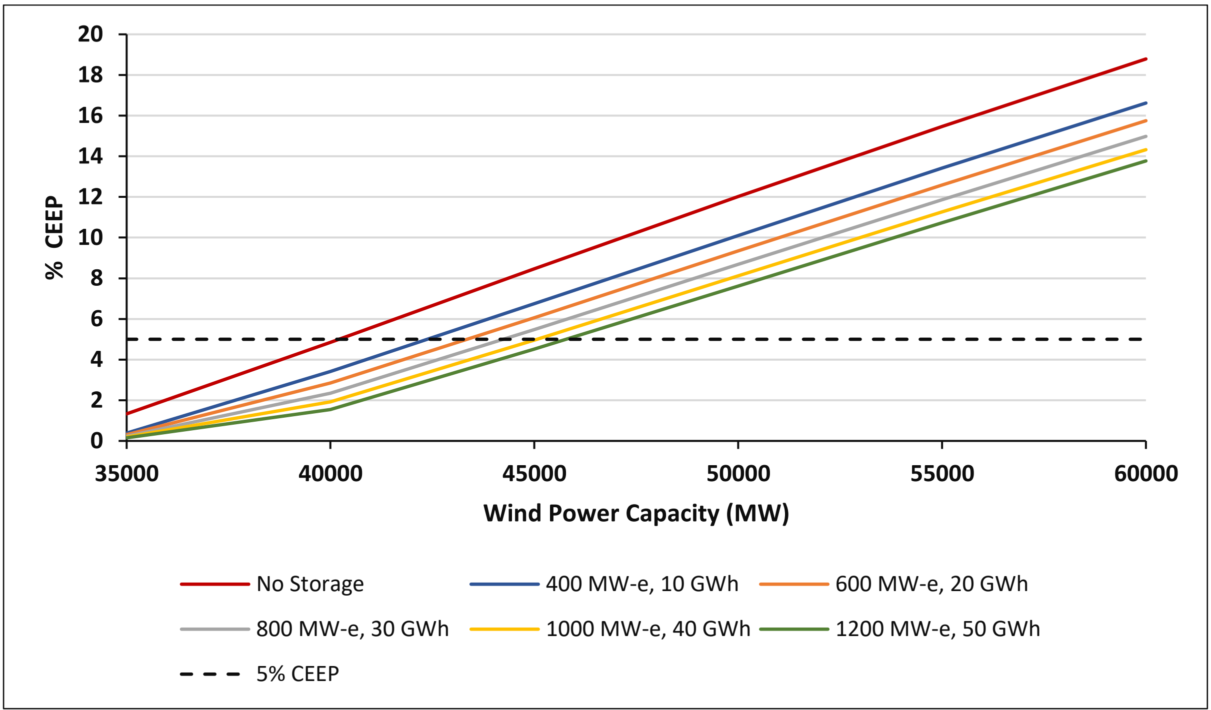


Figure 31: % CEEP for different capacities of wind power and PtH with TES in SWE_2045 scenario

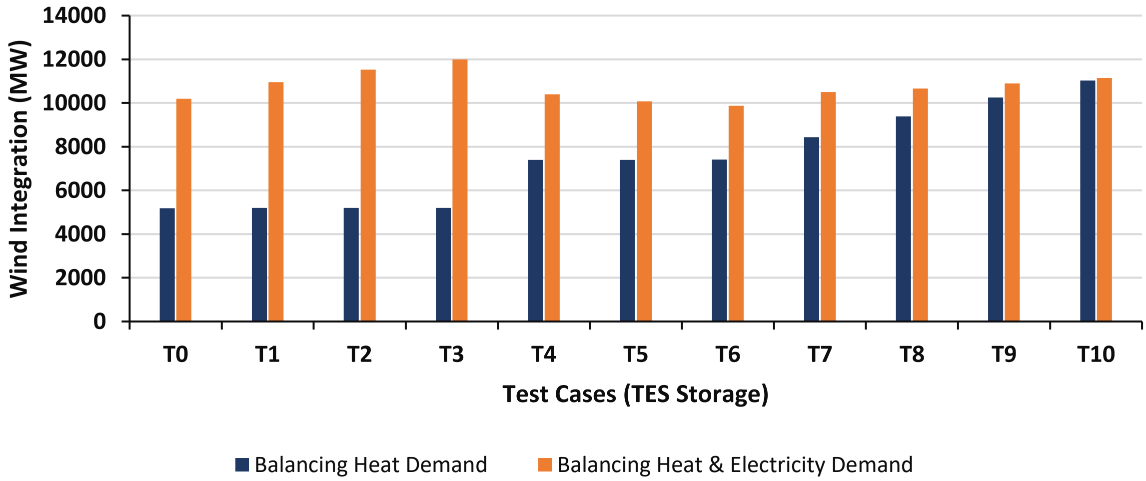
The storage cases illustrated in figure 31 correspond to T0, T4, T7, T8, T9, T10 under technical simulation and balancing heat demand strategy. The intersection of % CEEP line with the threshold of 5% indicates the maximum wind capacity that can be allowed in the system. As illustrated in the figure 31, increasing heat pump and TES capacities in district heating reduce % CEEP levels in the system, leading to higher integration of wind power. For instance, the line for no-storage intersects with the horizontal 5% CEEP line at x = 40191 MW. Therefore, the additional wind capacity that can be added to the base value of 35000 MW is 5191 MW. In comparison, adding heat pumps with 1200 MW-e & TES of 50 GWh leads to additional integration of 11032 MW.

As mentioned in Chapter 5, the technical simulation strategy is further divided into two types – balancing heat demand (HD) and balancing heat & electricity demand (H&ED). The SWE_2045 system was simulated for TES test cases T0 – T10 under both BHD and BH&ED. In balancing HD, the model aims to balance only heat demand of the system. Therefore, the hourly heat demand is mainly fulfilled by CHP followed by heat pumps and boilers. However, CHP also produces electricity along with heat, leading to higher levels of CEEP. In BH&ED, the model aims to balance both hourly heat and electricity demand and supply. Thus, the excess electricity by wind power plants is utilized by the heat pumps to cater to the district heating demand, leading to comparatively lower levels of CEEP. Table 23 demonstrates the difference in CEEP levels under balancing HD and balancing H&ED for storage cases T0 and T10. Similar outcome was observed for test cases T2 to T9.

Table 23: Reduction in CEEP due to addition of 1200 MW-e HP & 50 GWh TES in SWE_2045 system for various wind capacities under balancing HD and H&ED

Wind Capacity (MW)	**RES[10] (TWh)**	**Reduction in CEEP in balancing HD (%)**	**Reduction in CEEP in balancing H&ED (%)**
35000	171.2	88.59	35.29412
40000	184.56	68.04469	11.1413
45000	197.92	46.65472	11.03239
50000	1200	36.62859	10.08746
55000	400	30.58993	9.090909
60000	400	26.69946	8.174626

As shown in Table 23, the addition of a 1200 MW-e heat pump and a 50 GWh TES (storage case T10) significantly reduces CEEP levels in the balancing HD strategy compared to the reduction in balancing H&ED. Therefore, PtH coupled with TES performs better in the balancing HD strategy. This is because the excess electricity production levels are already low in balancing H&ED, even without HP & TES, because the model aims to balance electricity demand by reducing CHP production and fulfilling the hourly DH demand with thermal boilers in T0. However, adding HP further reduces CEEP, as the heat pump operation is prioritized over thermal boilers. The additional integration of wind power at 5% CEEP for each test case is depicted for both the strategies in figure 32.



[10] RES electricity indicates summation of production from wind, solar PV and hydropower wherein solar PV (9.71 TWh) and hydropower (67.93 TWh) are constant in all cases.

Figure 32: Additional integration of wind power at 5% CEEP in technical simulation strategy for different heat pump and TES capacities.

The figure shows considerable difference in integration levels between balancing HD and H&ED. In case of balancing HD, just increasing HP capacities in T1 to T3 does not increase wind integration due to the additional production from CHP and absence of TES. However, adding TES of 10 GWh in T4 increases the wind integration from 5201 MW in T1 to 7396 MW, as the storage helps to cater to the hourly heat demand. In contrast, it is counterintuitive for cases T1 to T6 in balancing H&ED. Increasing HP capacities in T1 to T3 increases the wind integration, as increasing HP capacities further reduce CEEP levels. However, when TES capacity is increased without increasing HP in T4 to T6, the wind integration actually reduces. This is because part of the heat demand is fulfilled by stored heat in TES, leading to a reduction in the operation of HP, which causes reduction in flexibility of PtH.

As shown in figure 32, the maximum additional wind integration in TES at 5% CEEP for 2045 scenario is 11032 MW in balancing HD and 11142 MW in balancing H&ED. Thus, SWE_2045 was simulated again by adding this additional wind capacity of 11032 MW to the base capacity of 35000 MW. Figure 33 shows the CEEP levels and total fuel supply and figure 34 shows the total cost & CO_2 emissions for this energy system in test cases T1 to 10 under BHD and BH&ED strategies.

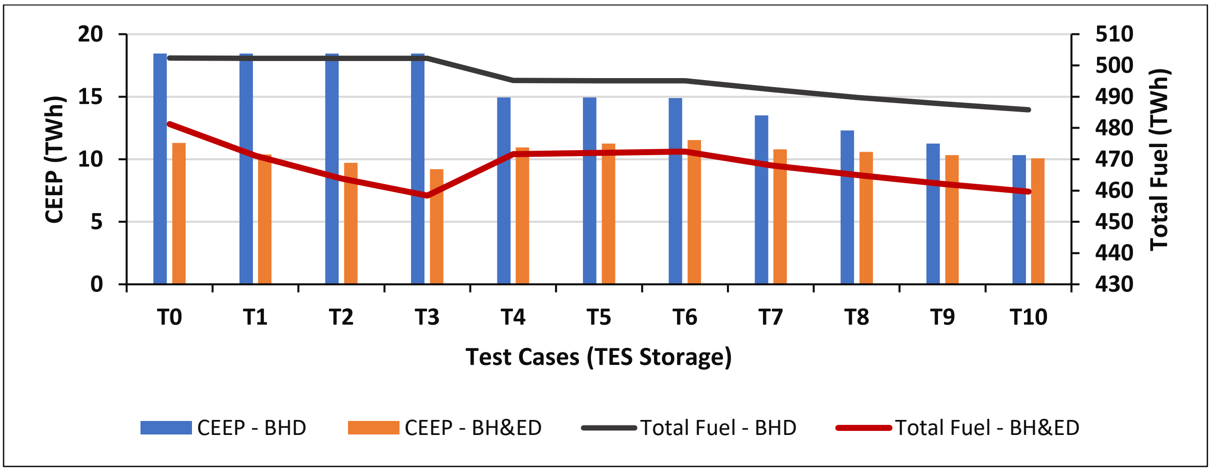


Figure 33: CEEP & Total fuel in test cases T1 to T10 for SWE_2045 energy system with wind capacity = 46,032 MW in technical simulation strategy

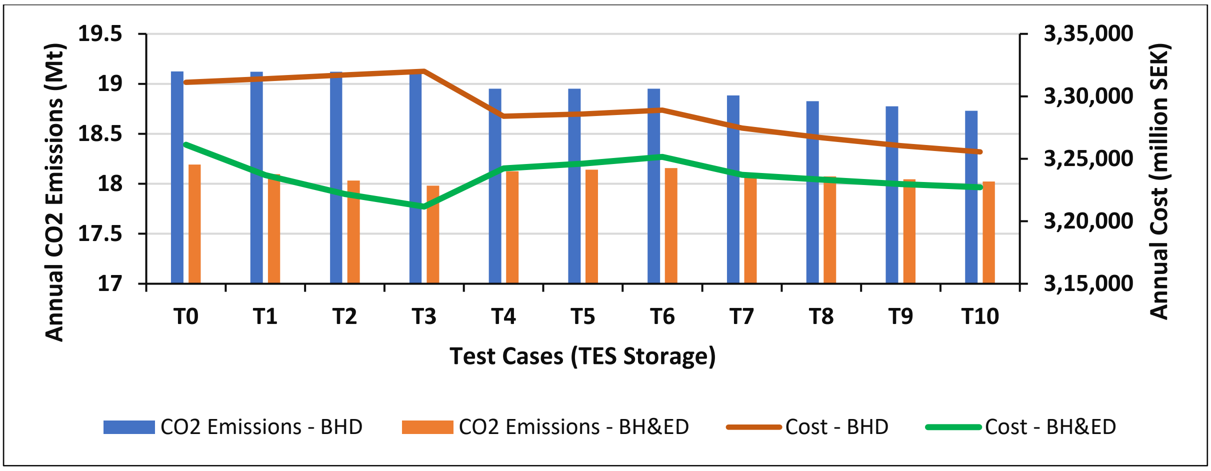


Figure 34: CO2 Emissions & Total fuel in test cases T1 to T10 for SWE_2045 energy system with wind capacity = 46,032 MW in technical simulation strategy

The total fuel balance in balancing H&ED is significantly lower than in balancing HD. For instance, the total fuel is 495.14 TWh for BHD and 472.06 TWh for BH&ED in test case T5. Nonetheless, the total fuel balance decreases as the HP and TES capacities increase, since the reduced operation of CHP and thermal boilers in both strategies leads to lower consumption of primary fuels. A similar trend can be observed for CO_2 emissions and annual cost in figure 34. Annual cost is primarily driven by the fuel and variable costs. Therefore, although increasing HP and TES capacities increases the annualized investment & fixed costs, the reduction in annual cost for higher HP & storage capacities is mainly due to the reduction of fossil fuels and CO_2 emission costs. In order to further evaluate the impact of PtH and TES in SWE_2045, with wind capacity at 46,032 MW, the energy system was simulated under test cases T4 and T10 with varying CHP capacities. Figures 35 shows the variation in heat production from different technologies.

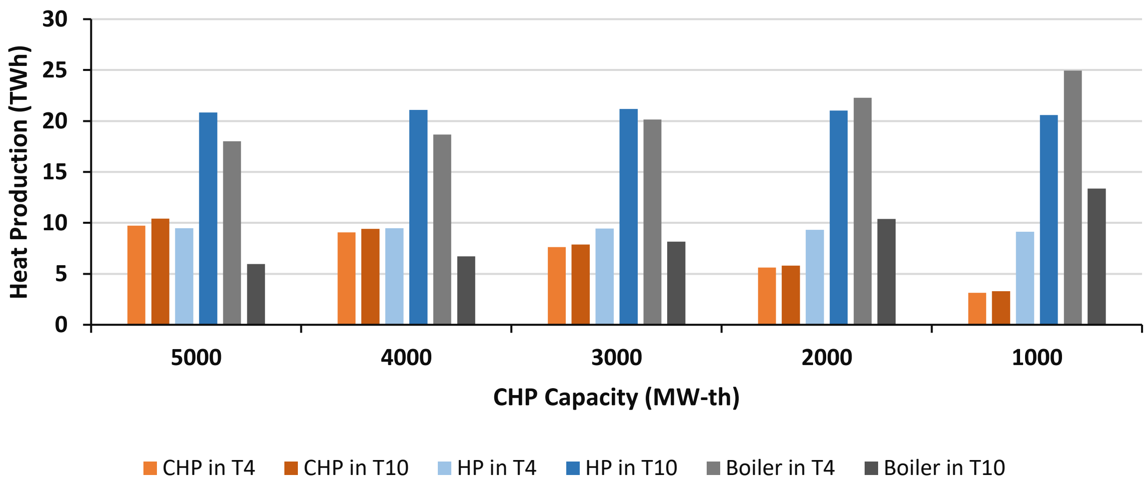


Figure 35: Production from CHP, HP and Boiler in T4 & T10 storage cases to cater to the DH demand in SWE_2045.

As depicted in figure 35, increasing HP and TES capacities from 400 MW-e and 10 GWh in T4 to 1200 MW-e and 50 GWh in T10 leads to considerable difference in heat production from HP and boilers. For all CHP capacity inputs shown in the figure, increasing HP and TES capacities reduce the production from boiler by 46% in 1000 MW-th CHP to 67% in 5000 MW-th as input. Table 24 shows the percentage of DH demand fulfilled by two different TES capacities.

Table 24: DH demand fulfilled by TES in test cases T4 and T10 in SWE_2045

CHP Capacity (MW-th)	% DH demand fulfilled by TES in T4 (10 GWh)	% DH demand fulfilled by TES in T10 (50 GWh)
1000	0.55	0.96
2000	0.73	0.93
3000	1.008	1.12
4000	1.46	1.72
5000	1.77	2.65

In addition to reducing the production from thermal boilers, increasing TES capacity also increases the % DH demand fulfilled by storage, as shown in table 24.

As explained in chapter 5, Test cases H1 to H5 for hydrogen storage were incorporated in SWE_2045 to evaluate the impact of hydrogen storage in a system without hydrogen demand. Electrolyser capacity was computed by EnergyPLAN based on demand for 1 TWh of hydrogen in the condensing power plant group, wind capacity input & CEEP. HP & TES are set at current levels of 400 MW-e & 42 GWh. Figure 36 shows additional wind integration for hydrogen storage starting from 0 GWh in H1 to 40 GWh in H5 in steps of 10 GWh for a computed electrolyser capacity of 6112 MW-e.

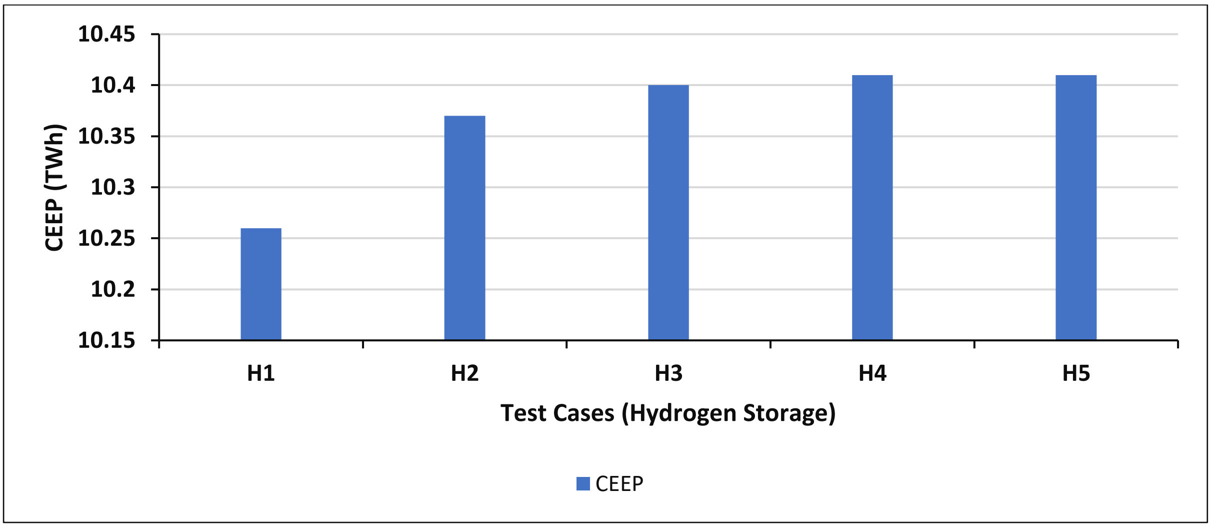


Figure 36: CEEP & Wind integration in test cases H1 to H5 for SWE_2045 energy under BH&ED technical simulation strategy

As observed in figure 36, the wind integration actually decreases with increase in storage capacity due to increase in CEEP levels. This behaviour is counterintuitive and also similar to the behaviour of cases T1 to T6 in TES with BH&ED strategy. This is because part of the hydrogen demand is fulfilled by the storage, leading to a reduced operation of electrolyser which in turn causes reduction in flexibility of Power-to-hydrogen.

As shown in figure 36, the maximum additional wind integration in hydrogen storage at 5% CEEP for SWE_2045 scenario is 10992 MW in BH&ED. Thus, SWE_2045 was simulated again by adding this additional wind capacity to the base capacity of 35000 MW. Table 25 shows annual cost, total fuel and CO_2 emissions of this energy system in each storage case.

Table 25: Annual cost, total fuel & CO2 emissions in various storage test cases for SWE_2045

Test Cases	Annual Cost (million SEK)	Total Fuel (TWh)	CO_2 Emissions (Mt)
H1	339,304	471.86	18.154
H2	339,647	471.86	18.153
H3	339,952	471.83	18.153
H4	340,256	471.79	18.153
H5	340,549	471.73	18.153

As shown in Table 25, the annual costs increase in each case due to the additional investment in storage and electrolysers. However, unlike TES, the total fuel balance and emissions almost remain the same level due to no changes in primary fuel consumption for district heating.

Test cases E0 to E3 were designed to evaluate battery storage in SWE_2045. The results show that wind integration increased by only 10 MW, from 10192 MW in E0 to 10202 MW in E1, and remained constant thereafter for E2 & E3. Therefore, the contribution of battery storage to wind integration was minimal. This behaviour is due to the fact that electricity supply in SWE_2045 exceeds demand. This factor is compounded by the utilization of excess electricity by heat pumps, reduction in production by CHP in BH&ED and external transmission of residual electricity.

6.2 NFF_2045

To determine CEEP and % CEEP for each storage, NFF_2045 was simulated for varying wind capacities from 65 GW to 90 GW in steps of 5 GW. Technical simulation strategy with balancing H&ED was chosen since it inherently reduces the CEEP compared to balancing HD, as established in the section 6.1. NFF_2045 was simulated for TES test cases T0 to T10 with hydrogen storage at 0 GWh. Based on the hydrogen demand of 45 TWh, the electrolyser capacity computed by the model is 16831 MW-e. The maximum additional wind integration in TES at 5% CEEP for NFF_2045 scenario is 18989 MW in test case T3. Thus, NFF_2045 was simulated again by adding this additional wind capacity to the base capacity of 65000 MW. Figure 37 shows the annual cost and total fuel supply for this energy system in test cases T1 to 10 under BH&ED strategy.

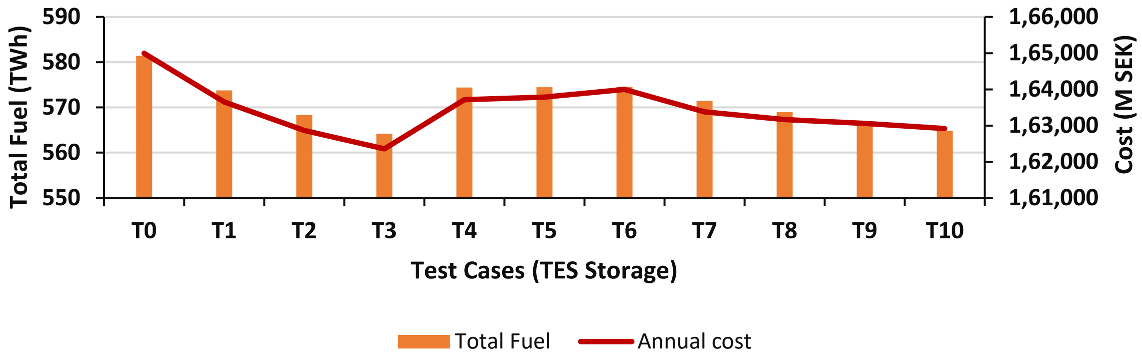


Figure 37: Annual cost & fuel in test cases T0 to T10 for NFF_2045

As shown in Figure 36, TES exhibits a similar behaviour to that of SWE_2045 in this scenario. The total fuel has increased by almost 100 TWh due to increased electrification of the transport and industrial sectors, as well as additional demand for hydrogen. However, even with the additional investments for electrolysers, the annual cost has significantly decreased compared to SWE_2045 due to the absence of expensive fossil fuel and CO_2 emission costs.

To further examine the impact of PtH and TES in NFF_2045, with wind capacity at 83,989 MW, the energy system was simulated under test cases T4 and T10 with varying CHP capacities. Figures 38 shows the variation in heat production from different technologies.

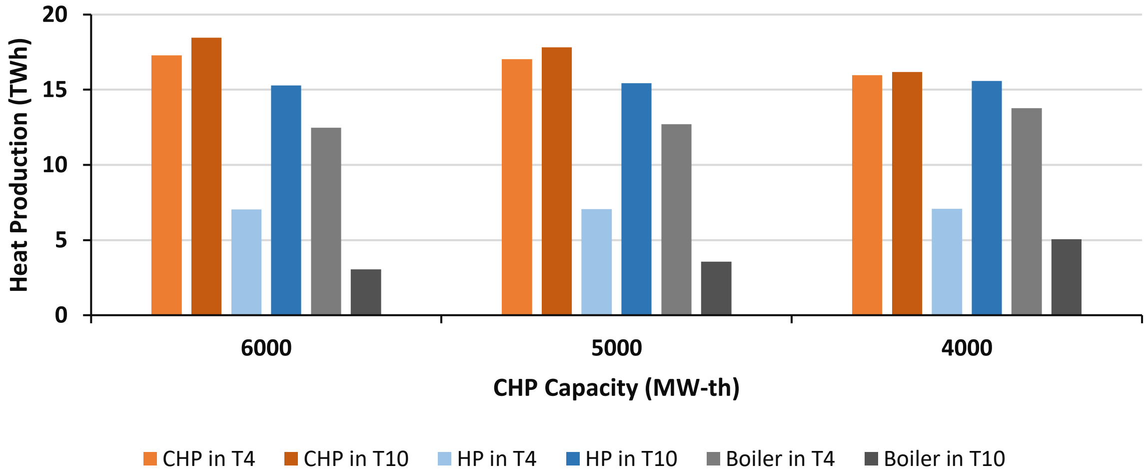


Figure 38: Production from CHP, HP and Boiler in T4 & T10 storage cases to cater to the DH demand in NFF_2045.

As shown in figure 38, similar to SWE_2045, increasing HP and TES capacities leads to considerable difference in heat production from HP and boilers. For all CHP capacity inputs shown in the figure, increasing HP and TES capacities reduce the production from boiler by 63% in 4000 MW-th to 75.64% in 6000 MW-th as input. Table 26 shows the percentage of DH demand fulfilled by two different TES capacities.

Table 26: DH demand fulfilled by TES in test cases T4 and T10 in NFF_2045

CHP Capacity (MW-th)	% DH demand fulfilled by TES in T4 (10 GWh)	% DH demand fulfilled by TES in T10 (50 GWh)
4000	1.9	2.11
5000	2.23	3.43
6000	2.33	4.27

In addition to reducing the production from thermal boilers, increasing TES capacity also considerably increases the % DH demand fulfilled by storage, as shown in table 26.

In order to simulate hydrogen storage in a system with considerable hydrogen demand, NFF_2045 was equipped with test cases ranging from 0 GWh in H0 to 100 GWh in H10, in increments of 10 GWh. HP & TES capacities were set to 0. The model computed electrolyser capacity of 16831 MW-e. Figure 39 shows the change in % CEEP with respect to increasing wind capacity inputs for various storage capacities.

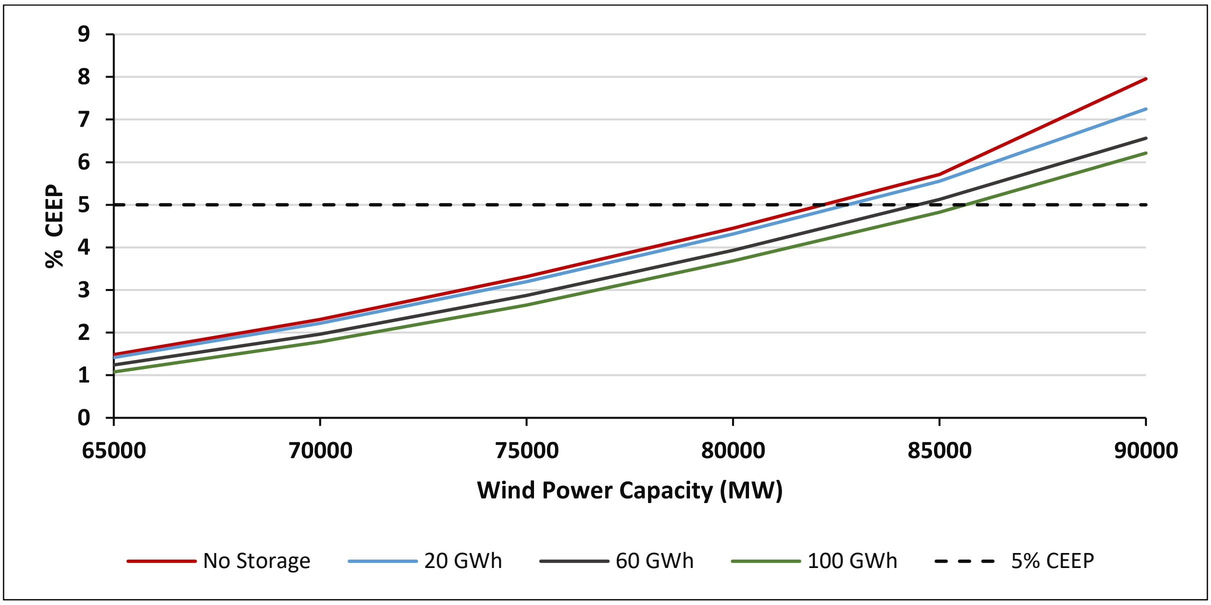


Figure 39: % CEEP for different capacities of wind power and Power-to-hydrogen with HS in NFF_2045

Figure 40 illustrates the additional integration of wind power in each test case for different storage profiles.

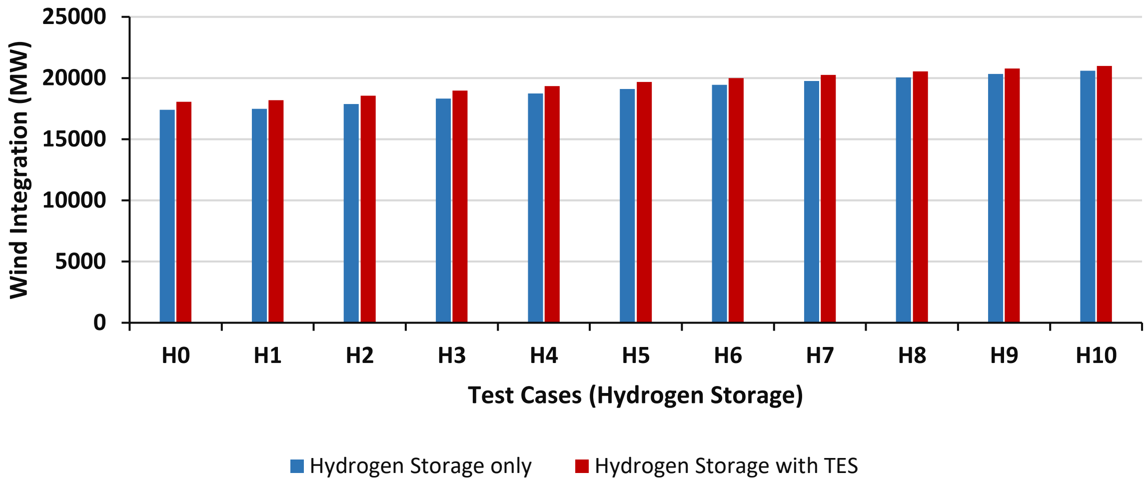


Figure 40: Additional integration of wind power at 5% CEEP for different storage profiles in NFF_2045

In contrast to SWE_2045, increasing hydrogen storage in NFF_2045 decreases the CEEP in the system. This is mainly due to a significantly higher demand in the industrial sector. Increasing storage capacity facilitates increased operation of the electrolyser to meet the hourly demand from the industry. The maximum additional wind integration in hydrogen storage at 5% CEEP is 20,599 MW in test case T10. Figure 40 shows that adding current levels of HP (400 MW-el) and TES (42 GWh) to the system further reduces CEEP levels leading to increase in wind integration.

The maximum additional wind integration in hydrogen storage coupled with HP & TES at 5% CEEP is 20994 MW. Thus, NFF_2045 was simulated again by adding this additional wind capacity to the base capacity of 65000 MW. Figure 41 shows the annual cost and total fuel balance for this energy system in test cases H1 to H10.

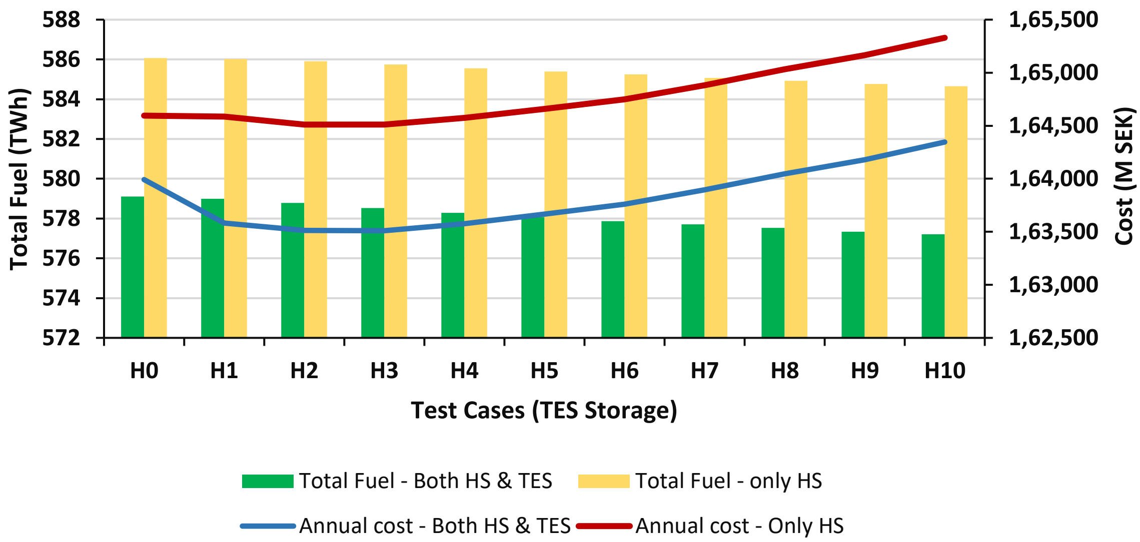


Figure 41: Annual cost & fuel in test cases H0 to H10 for NFF_2045

As shown in Figure 41, the total fuel decreases as the hydrogen storage increases for both profiles. However, the difference in fuel balance between hydrogen storage alone and hydrogen storage combined with HP & TES is around 7 TWh. Similarly, annual costs are lower when HP & TES are combined with hydrogen storage, even with the increased annualized investment cost, due to decreased variable costs resulting from less production from CHP and thermal boilers. Although adding hydrogen storage reduces CEEP, unlike TES, decreasing CEEP does not induce a considerable reduction in total fuel, since hydrogen storage does not affect production from CHP and thermal boilers. Furthermore, the annual cost curves show a nominal reduction until test case H3 (30 GWh) as the variable costs offset the annualized investment and fixed costs. However, starting from test case H4 (40 GWh), the net reduction in CEEP decreases leading to lower variable costs, which are offset by the increase in investments in the storage.

Hydrogen storage was further assessed by simulating NFF_2045 with wind a lower wind capacity at 60,000 MW, under test cases H0 and H10. Figure 42 shows the variation in electricity import and export for different levels of storage. Table 27 shows the percentage of hydrogen demand fulfilled by various storage capacities.

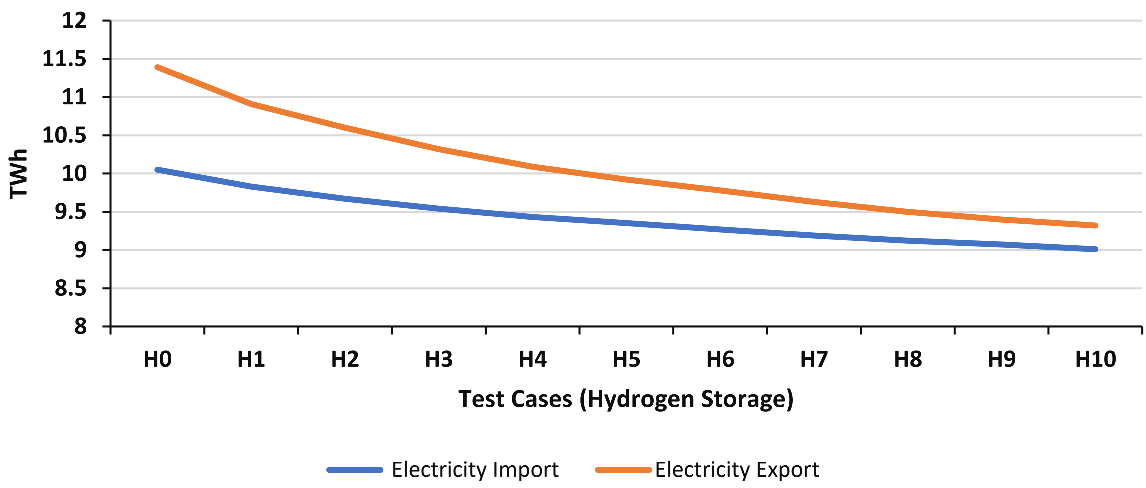


Figure 42: Electricity import and export in test cases H0 to H10 in NFF_2045 for wind capacity at 60 GW

Table 27: Hydrogen demand fulfilled by various storage capacities in NFF_2045

Capacity (GWh)	% Hydrogen demand fulfilled by storage
10	1.62
20	2.57
30	3.3
40	3.9
50	4.37
60	4.78
70	5.15
80	5.5
90	5.8
100	6.2

Figure 42 shows that increasing hydrogen storage in a system with significant hydrogen demand leads to notable decrease in both electricity import and export. However, the annual cost of the system increases by 7 to 8% compared to the system with wind capacity at 85.9 GW. The is because, although annualized investment and fixed costs increase for a system with higher wind capacity, the operational costs reduce by almost 42.7% due to reduction in electricity imports and increase in exports at higher wind capacities, leading to net reduction in total annual cost. Furthermore, increasing hydrogen storage also increases the share of demand fulfilled by the storage as shown in table 27.

Test cases E0 to E3 were designed to evaluate battery storage without hydrogen storage, while test cases EH0 to EH3 were formulated to examine battery storage in combination with hydrogen storage of 30 GWh. Figure 43 shows the wind integration and annual cost for each test case.

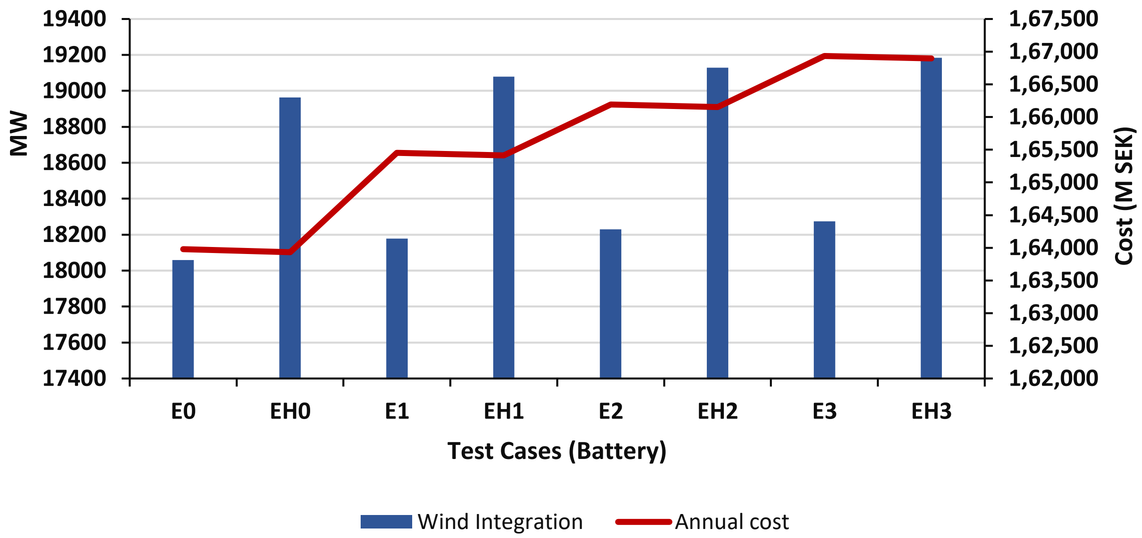


Figure 43: Annual cost & wind integration in test cases E0 to EH3 for battery storage in NFF_2045

Although the additional wind integration is better compared to SWE_2045 for the same storage capacities, the contribution of battery storage was still minimal compared to TES and HS. This is because of excess electricity being utilized by heat pumps, reduction in electricity production by CHP in BH&ED, and external transmission of residual electricity.

6.3 Sensitivity Analysis

This section focuses on parameters other than storage that impact the outcome of the simulation. As explained in Chapter 5, CEEP represents excess electricity in the system after demand and export. The amount of export depends on the External Transmission Line (ETL) capacity set in the the model. ETL is set at 11950 MW in both the scenarios, considering current capacity and anticipated future expansions described in Appendix A.2. Figure 44 shows the variation CEEP levels for different ETL capacities in SWE_2045.

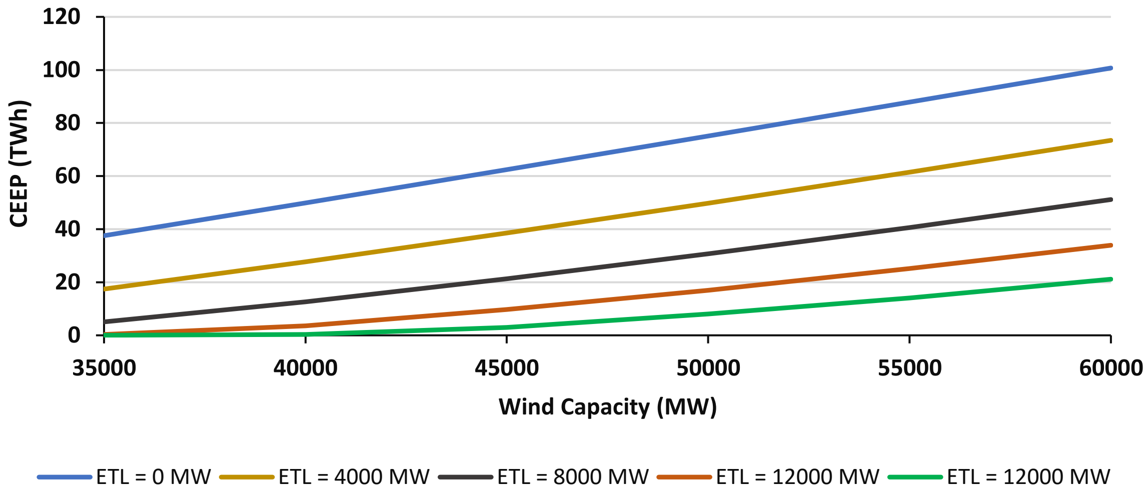


Figure 44: CEEP under different ETL capacities in SWE_2045 scenario

As shown in Figure 44, the addition of ETL reduces the % CEEP in the system and facilitates VRES integration. However, increasing ETL alone does not reduce the total fuel costs, as energy conversion systems with storage are required to achieve this. Nevertheless, increasing ETL does reduce annual costs due to the revenue earned from exporting electricity.

Both SWE_2045 and NFF_2045 have nuclear and hydropower as base load plants, with capacities of 3650 MW and 16500 MW respectively. Although both systems have large-scale wind integration, the installed capacities of nuclear power plant also affect the CEEP, fuel balance, and annual cost, as shown in Tables 25 and 26 for SWE_2045 and NFF_2045 respectively.

Table 28: CEEP, annual cost, total fuel & CO_2 emissions for different nuclear power capacities and wind input of 35000 MW in SWE_2045

Installed Capacity (MW)	Production (TWh)	CEEP (TWh)	Total Fuel (TWh)	Annual Cost (million SEK)	CO_2 Emissions (Mt)
0	0	0.07	377.21	321940	18.599
1000	7.68	0.12	398.14	323702	18.512
2000	15.36	0.18	419.22	325540	18.432
3000	23.05	0.27	440.44	327404	18.356
4000	30.73	0.39	461.81	329285	18.285
5000	38.41	1.87	483.36	331863	18.23

Table 29: CEEP, annual cost, total fuel, electricity import & export for different nuclear power capacities and wind input of 65000 MW in NFF_2045

Installed Capacity (MW)	Production (TWh)	CEEP (TWh)	Total Fuel (TWh)	Annual Cost (million SEK)	Import (TWh)	Export (TWh)
0	0	1.98	481.56	169226	17.5	10.51
1000	7.68	2.33	496.54	169549	14.23	11.61
2000	15.36	2.73	511.16	169898	11.24	12.81

3000	23.05	3.17	525.5	170287	8.51	14.1
4000	30.73	3.67	541.68	171242	6.57	16.78
5000	38.41	4.23	561.73	173175	5.67	21.76

As observed in tables 25 and 26, increasing nuclear power has a nominal impact on CEEP levels. However, nuclear power plants affect the total fuel since primary nuclear energy is calculated as production divided by the efficiency of the nuclear power plant. Although nuclear power does not significantly impact CEEP, it reduces imports and enhances exports in NFF_2045, which has large scale wind integration and higher levels of electrification in the transport and industrial sectors.

The choice of simulation strategy is another primary aspect that influences the simulation results. So far, the results discussed in Sections 6.1 and 6.2, as well as the sensitivity analysis in this section, are the outcome of technical simulation. However, EnergyPLAN also offers a market-economic simulation strategy, as explained in Chapter 5. This strategy seeks to determine the least-cost solution to balance the demand and supply, instead of the least fuel-consuming technology. Table 27 shows the differences in results for technical simulation with BH&ED strategy and market-economic (ME) simulation strategy for both scenarios.

Table 30: CEEP, total fuel and annual costs in technical and market economic simulation strategies

Scenario	Wind Capacity (MW)	Type of Storage	Simulation Strategy	Hydro-electricity (TWh)	CEEP (TWh)	Total Fuel (TWh)	Annual Cost (million SEK)
SWE_2045	46032	HP = 1000 MW-e, TES = 42 GWh	Technical	67.93	10.33	462.1	322,983
			ME	49.4	0.85	433.79	339,699
NFF_2045	84184	El = 16831 MW-e, HS = 100 GWh	Technical	67.93	15.07	577.21	164,346
			ME	63.02	11.02	567.66	178,974

As shown table 27, in the market economic simulation, CEEP and total fuel are lower due to reduced production from hydro power plants. However, the annual cost is higher due to an increase in variable costs associated with fuel consumption and a reduction in revenue from electricity exports. On the other hand, the technical simulation is more accurate as it takes into consideration the long-term costs over the lifetime of technologies rather than just short-term costs.

6.4 Discussion

The results presented in sections 6.1 and 6.2 show the impact of storage technologies on energy systems in the context of sector integration, additional wind integration, total fuel and annual costs.

Large-scale VRES integration is characterized by excess electricity production in intermittent hours. As stated in chapter 5, this residual or excess electricity beyond what a system can utilize and export is not desirable as it affects the functioning of the power system. Therefore, reducing this excess electricity not only improves the stability of the system, but bringing it under 5% of total RES electricity also enables adding more wind power to the system.

In this regard, HP coupled with TES enhances wind integration in both SWE_2045 and NFF_2045 by utilizing excess electricity to fulfil DH demand. For instance, incorporating HP (1200 MW-e) and TES (50 GWh) into the system can increase wind capacity from 29.12% to 31.8% in SWE_2045 and 26.78% to 29.17% in NFF_2045. However, the performance of TES varies depending on the type of simulation strategy used. Balancing HD focuses solely on meeting hourly heat demand, leading to heat production from combined heat and power (CHP) causing additional production of electricity and thereby increasing net electricity production and total fuel. Simply adding HP without TES does not enhance wind integration or reduce total fuel due to the limited operation of HP. However, adding TES with HP enhances wind integration and also improves fuel balance due to increased operation of HP. On the other hand, TES in balancing H&ED focuses on balancing electricity demand, and hence reduced production from CHP already decreases excess electricity production, inherently facilitating more wind integration for the same HP and TES capacities. Therefore, both HP and TES must be incrementally increased in the balancing H&ED strategy to facilitate additional wind integration. Considering current levels of aggregated HP and TES capacities of around 400 MW-e and 40-42 GWh TES in the DH systems, increasing the HP capacity while retaining the current level of TES can improve wind integration in the future energy system in 2045.

In addition to enhancing wind integration, TES also reduces annual fuel consumption and costs mainly by reducing the production from boilers in DH in both scenarios. For instance, when CHP capacity is 5000 MW-th in SWE_2045, the production from boiler in T10 almost reduces by 67% compared to T4. Similar is the case in NFF_2045 where the reduction in T10 compared to T4 is 72%. Further, the % DH demand fulfilled by TES in T4 is 2.33% while it is 4.27% in T10 in NFF_2045. In comparison, it is 2.65% in T10 in SWE_2045. This demonstrates that the contribution of storage increases in a system with relatively higher electrification. Another interesting observation is that when HP and TES capacities are increased in both the scenarios, although the investment and fixed costs increase, the net annual cost still marginally decreases due to the considerable reduction in variable cost. For example, the net annual cost decreases by 0.47% with T10 compared to T4, although T10 has increased HP and TES capacities compared to T4. Thus, the results demonstrate that PtH coupled with TES in DH performs well in energy systems characterized by both comparatively low and high levels of VRES integration and electrification.

On the other hand, the results in both the SWE_2045 and NFF_2045 show that electrolysers and hydrogen storage are only necessary when the energy system requires significant amounts of hydrogen. As illustrated in SWE_2045, adding hydrogen storage to an energy system with no substantial hydrogen demand and where the only purpose is to utilize excess electricity is not recommended. For example, in SWE_2045, adding 1200 MW-e of HP capacity and 50 GWh of TES increases wind integration by 31.8%, while adding 6112 MW-e of electrolyser capacity and 10 GWh of hydrogen storage increases the same by 31.1%. Although the enhancement of wind integration is almost at the same level, the annual cost for the system with hydrogen storage increases by 5.1%. Besides, TES and HP are already part of the Swedish energy system, and hence, enhancing PtH coupled with TES is a better alternative than installing electrolysers and hydrogen storage in an energy system without considerable hydrogen demand. However, hydrogen storage demonstrates better performance in an energy system with a significant hydrogen demand, as observed in NFF_2045. For instance, adding a 50 GWh hydrogen storage increases wind integration from 26.78% to 29.3%. In addition, results in section 6.2 indicate that the integration of wind power is further improved (32.2%) when hydrogen storage is coupled with HP and TES. The impact of hydrogen storage was also studied with a lower wind capacity (60 GW) in NFF_2045 to determine the impact on electricity export and import. The results in table 28 show that increasing hydrogen storage enhances the percentage of hydrogen demand fulfilled by storage (6.2% in case H10) leading to reduction in both electricity import and export by as shown in figure 42. Further, the increase in annual cost between H0 and H10 is only 0.85% even with the substantial increase in hydrogen storage between the two test cases. This marginal net increase is due to the considerable reduction in variable costs. Another interesting observation here is that although hydrogen storage leads to reduction in import and export, the annual cost and total fuel also vary based on the wind capacity. For instance, the annual cost of a system with 50 GWh hydrogen storage increases by 7.8% even when the wind capacity reduces from 85.994 GW to 60 GW. This is due to the reduction in net export and also due to increased operation by CHP and PPs to cater to the electricity demand. On the other hand, the reduction in total fuel due to increase in storage from H0 to H10 (100 GWh) is 0.326% in case of 85.994 GW whereas it is 0.79% in case of 60 GW. However, compared to TES, hydrogen storage does not significantly reduce the total fuel since it does not decrease heat production from boilers.

Compared to TES and HS, the extent of additional integration due to battery storage is quite minimal. Also, the contribution of battery storage varies based on the demand and supply characteristics as noticed in SWE_2045 and NFF_2045. For instance, the wind integration increased by 29.1% in SWE_2045. The annual cost for this amount of wind integration is 1.3% higher than that of TES. Similarly, in NFF_2045, the wind integration increased by up to 28.11%. However, the annual cost for this extent of integration is 2% higher than that of hydrogen storage. Besides, unlike TES, the total fuel does not reduce as battery storage.

Overall, considering additional wind integration, reduction in total fuel, annual costs and emissions as criteria, PtH with TES emerges the most favourable option than hydrogen storage in both the scenarios. This is due to the fact that HP and TES integrate electricity and DH sectors leading to increased flexibility in an energy system like Sweden that has significant electricity and heat demand. Besides, it also facilitates large-scale VRES integration as shown in the results from both the scenarios. In comparison, although hydrogen storage improves wind integration at almost same level as TES, the annual costs are marginally higher as it does not reduce fuel consumption in DH. However, when incorporated in an energy system where there is hydrogen demand from other sectors like 45 TWh from industry in NFF_2045, the contribution of hydrogen storage is substantial in terms of utilizing electricity from VRES to cater to the demand. Thus, hydrogen storage integrates electricity and industrial sectors, which has the potential to improve flexibility in the future energy system in the context of implementation of HYBRIT. In comparison, aggregated battery storage in a cross sector set up does not improve flexibility to a great extent, since TES and hydrogen storage emerge as better alternatives in utilizing VRES electricity in both the scenarios.

Furthermore, when comparing wind integration levels in SWE_2045 and NFF_2045, it is evident that wind integration ranges from 10 GW to 11 GW in SWE_2045, whereas in NFF_2045, it ranges from 17 GW to 21 GW. This difference is due to the fact that excess electricity is lower in NFF_2045, which in turn signifies increased electricity demand from further electrification of transport and industry compared to SWE_2045. Therefore, increased electrification not only reduces emissions but also increases the utilization of VRES electricity.

Given the impact of storage in both scenarios under different test cases, the next question that requires further research is the optimal mix of storage technologies in the future energy system. The scenarios mentioned above represent only two different energy systems based on different combinations of inputs. Although determining the optimal mix of storage technologies requires the formulation of an optimization problem with techno-economic constraints, the optimal mix can be ostensibly deduced based on the performance of each storage, given the considered storage cases and their impact on the system.

In SWE_2045, as explained, HP with TES offers better integration, a reduction in annual cost, and fuel. Therefore, given the current TES capacity of around 42 GWh and HP at 400 MW-e, the system parameters can be improved by simply increasing the HP capacity to 1200 MW-e at the same storage level. However, in the case of NFF_2045, the annual cost is lowest when HS = 30 GWh. Hence, the combination of HP and TES at 1200 MW-e, 42 GWh, HS = 30 GWh, and battery storage at 4 GWh with a charge/discharge capacity of 1000 MW-e emerges as an optimal mix of storage technologies.

Nevertheless, the results can vary depending on other system parameters as shown in the sensitivity analysis. For instance, external transmission capacity plays a major role in determining the wind integration as shown in figure 44. In addition, as shown in table 30, installed capacity of nuclear power greatly influences the electricity import and export in an energy system such as NFF_2045 with very high level of electrification and further demand from electrolysers. Further, the choice of simulation strategy is another vital factor that influences the simulation results. For instance, unlike technical simulation, market-economic simulation strategy seeks to determine the least-cost solution to balance the demand and supply, instead of the least fuel-consuming technology as shown in table 27. Although the excess electricity and total fuel are lower in market-economic strategy, the annual cost is higher due to an increase in variable costs associated with fuel consumption and a reduction in revenue from electricity exports. But, the results in this strategy are highly sensitive as it is based on current Nordpool market design. However, the market conditions may potentially vary in the future due to highly intermittent nature of VRES. Therefore, technical simulation is more accurate as it takes into consideration the long-term costs and the lifetime of technologies rather than just short-term costs.

Finally, in the context of all the results and inferences discussed in this chapter, following are some limitations to this study. In addition to ETL and nuclear capacity, excess electricity and fuel balance also depend on the distribution files used for various demand and supply parameters. These distribution files are based on the current characteristics of demand and supply in Sweden. Additionally, the cost data is estimated based on the data available in current literature and reasonable assumptions. A change in the cost of fossil fuels, CO_2 prices, investment cost of electrolyser, HP, hydrogen storage or TES in the future can change the results considerably. The same applies to discount rates, price elasticity, and electricity market prices in the future. Therefore, the outcome of the simulation can change depending on economic and technological evolution in the future.

Besides, this study examines the contribution of different storage technologies at the national level and hence, it does not capture regional congestions or bottlenecks in SE1, SE2, SE3, and SE4. Although the study shows the impact of storage in terms of balancing demand and supply, installing hydrogen or thermal energy storage in the order of GWh and large-scale integration of wind energy comes with its own set of technical and economic constraints and challenges. Thus, the results presented in this study are based on a delicate balance of estimated and available input data and considerations in the scenarios.

6.5. Contribution to Sustainability

Energy transition plays a crucial role in addressing the dire consequences of climate change. While there are many initiatives in Sweden to decarbonize the energy sector, the large-scale integration of VRES, especially wind power and a higher degree of electrification in transport and industrial sectors present new challenges in terms of balancing the energy system.

Therefore, this study focuses on examining the impact of HP and TES, HS coupled with the production of electrolytic hydrogen, and battery storage in the context of sector integration and no fossil fuels. It aligns with the UN's sustainable development goal SDG 7 (affordable and clean energy) and SDG 13 (climate action) by focusing on enhancing the flexibility of VRES systems that do not rely on fossil fuels.

However, implementation of large-scale VRES and storage technologies has both advantages and disadvantages in the context of sustainable development. For example, hydrogen production via electrolysis and large-scale HS creates a new avenue within the energy sector, which has the potential to boost innovation, augment industrial and economic growth, and create employment and revenue. However, producing hydrogen via electrolysis requires a huge amount of water, electricity and storage infrastructure, which can potentially impact environmental integrity in terms of both life on land and water, and also affect both current and future generations in terms of resource availability.

Similarly, large-scale wind integration requires resources in terms of land, raw materials, and discarding wind turbines at the end of their life cycle. Although sector integration and storage facilitate responsible and efficient production, implementing battery storage also increases the demand for raw materials, which can adversely affect the ecology and impact both current and future generations in the mining region.

In comparison, Sweden has an extensive district heating network with heat pumps (HP) and thermal energy storage (TES). Augmenting HP capacity at the current level of TES can potentially reduce primary fuel consumption and system costs, thereby reducing environmental and socio-economic impact.

In essence, sector integration, supplemented by storage, has the potential to improve flexibility and pave way for efficient utilization of resources in the energy sector. However, it is important for policymakers and stakeholders in the industry to have a comprehensive and holistic overview of this dimension. Further research into storage technologies is very much required to mitigate the techno-economic challenges and most importantly ecological, economic and social impact in all stages of the life cycle. In addition, the cost of fossil fuels, CO_2 prices, and investment in VRES, HP, electrolysers, and storage are crucial in shaping the energy system of the future. Reduction in the cost of VRES and storage technologies with parallel increase in the price of fossil fuels is key to establishing an energy system with a minimum to zero carbon footprint. Therefore, it is also important to focus on creating a conducive energy market to ensure that heat and electricity are accessible to all socio-economic groups both now and in the future.

7. Conclusion & Future Scope

Sweden has formulated ambitious goals to decarbonize the energy system including transport and industrial sectors by 2045. In order to achieve this, the country plans to increase electrification, augment wind power capacity, implement the HYBRIT project, and increase the use of biomass and biofuels. However, energy transition on such a large-scale requires a comprehensive analysis of the national energy system to explore the potential of sector integration through Power-to-heat and Power-to-hydrogen strategies.

In this context, this thesis examined the role of TES coupled with heat pumps, hydrogen storage, and batteries in Sweden's future energy system characterized by high levels of intermittent wind energy, increased electrification of transport and industrial sectors, and significant hydrogen demand in the industry. Two scenarios, SWE_2045 and NFF_2045, were formulated to represent two different energy systems distinguished by different levels of electrification. Both energy systems were configured in the EnergyPLAN modelling tool, and storage technologies were incorporated under various test cases.

The results indicate that HPs coupled with TES has the potential to increase wind integration from 29.12% to 31.8% in SWE_2045 and 26.78% to 29.17% in NFF_2045. Further, incorporating HP & TES reduces heat production from boilers by 67% to 72% depending on the scenario, leading to overall reduction in total fuel and annual costs by at least 2.5% and 0.5% respectively. Also, the analysis shows that the contribution of storage increases in a system with relatively higher electrification. Conversely, the wind integration is 31.1% in SWE_2045 with hydrogen storage. The annual cost increases by 5.1% compared to TES. However, it exhibits better performance in NFF_2045, wherein the wind integration increases from 26.78% to 29.3%. Furthermore, increasing hydrogen storage in NFF_2045 with lower wind capacity (60 GW) reduces both electricity import and export levels and simultaneously increases the contribution of storage in fulfilling the hydrogen demand from 1.62% to 6.2%. Compared to TES and HS, the contribution of battery storage is minimal in a cross-sector set-up. In addition to negligible reduction of total fuel, for wind integration around 28% to 29%, the annual cost of a system with battery storage is 1.3% to 2% higher than that of the system with TES and hydrogen storage respectively.

Therefore, HPs coupled with TES can improve flexibility in both scenarios. Hydrogen storage is not a promising option if the end goal is only to store excess electricity, as shown by the results in SWE_2045. However, it demonstrates better utilization in terms of wind integration, reduction in electricity import and export when there is a considerable demand for hydrogen, as in the case of NFF_2045. The contribution of batteries in wind integration is minimal in both scenarios due to the utilization of excess electricity by heat pumps, reduction in production by CHP in balancing H&ED, and external transmission of residual electricity.

However, the results presented in this study are based on the estimated and available input data and considerations in the scenarios. Therefore, the choice of storage technology in the future depends on its technical and economic evolution and other factors such as regional constraints and energy policies.

The model and scenarios can be extended to study other storage alternatives such as Carbon Capture and Storage (CCS) and CAES. Since the model focuses on analysis at national scale, it is important to explore bottlenecks and challenges at regional levels in SE1, SE2, SE3, and SE4. The scenarios formulated in this study do not consider other flexibility options, such as demand-side management, smart charging of electric vehicles, or the use of electrolytic hydrogen to produce electro-fuels. Therefore, further research is required in this direction. Hydrogen demand in the considered only for industrial sector. Further research is required to evaluate hydrogen storage in transport sector in the context of fuel cell vehicles. This study focuses on balancing heat and electricity demand at every hour, aiming to establish demand and supply balance. However, it does not consider the constraints of storage technologies. Therefore, the two energy systems should be simulated with a different ESM to address this limitation.

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Appendix

This section contains description of inputs & distribution files used to implement different scenarios in EnergyPLAN application.

A.1 Inputs: Reference Model 2019

Parameter	Value	Description	Reference
Demand			
Electricity demand (TWh)	136.3836	Net Demand (incl. transmission losses)	[17], Sec 6.2
Electric Heating – IH (TWh)	20.93372	Residential & services sector	[17], Sec 3.3
Elec. Transport (TWh)	2.9096	Electricity demand in Transport Sector	[17], Sec 5.1
Fixed Import / Export (TWh)	26.1605	Net electricity export	[17], Sec 6.2
IH – Oil Boiler (TWh)	0.796	Individual Heat Demand - Energy used for space heating, hot water in households & commercial buildings.	[17], Sec 3.4
IH – NG boiler (TWh)	0.721		
IH – Biomass boiler (TWh)	9.315		
DH – Group 1 (TWh)	17.33	District Heating Demand (Heat only plants)	[57], Sec 10
DH – Group 3 (TWh)	40.33	District Heating (CHP, Heat Pumps, Boilers)	
DC – Group 3 (TWh)	1.098	District Cooling Demand	[57], Sec 15
I + V Coal (TWh)	13.1	Industry + Various (agriculture, forestry, fishing, construction, energy sector own use, losses).	[17], Sec 1.1, 1.3, 4.1
I + V Oil (TWh)	18.89		
I + V NG (TWh)	4.725		
I + V Biomass (TWh)	58.1		
Transport – Jet Fuel (TWh)	1.858	Aviation Fuel	[17], Sec 5.1
Transport – Diesel (TWh)	38.584	Includes diesel, heavy & light fuel oils	
Transport – Petrol (TWh)	23.149	Gasoline	
Transport – NG (TWh)	0.2813	Natural Gas	
Transport – Biofuels (TWh)	16.5825	Biofuels	
Supply			
Thermal Boiler G3 (MJ/s)	3500	Input from EnergyPLAN Sweden 2009 Model as exact data is not available	[121]
CHP (MW)	6839	Condensing power + CHP (Electric)	[57], Sec 3.0
Condensing PP2 (MW)	1481	Gas turbines for reserve	[57], Sec 3.0
IC – Nuclear (MW)	8624	Installed Capacity of Nuclear Power	[57], Sec 3.0
IC – Hydropower (MW)	16,462	Installed Capacity of Hydro Power	
IC – Wind (MW)	8681	Installed Capacity of wind power	
IC – Solar PV (MW)	698	Installed Capacity of Solar PV	
Prod. Nuclear (TWh)	66.130	Production from Nuclear Power Plants	
Prod. Hydropower (TWh)	65.393	Production from hydroelectric Plants	
Prod. Wind (TWh)	19.847	Production from Wind Power Plants	
Prod. Solar PV (TWh)	0.6630	Production from Solar PV	
ITL Capacity (MW)	10,350	International Transmission Line Capacity	[19], Sec 4.5.1
Heat Pump (MWe) & COP	400, 3.3	HP at full capacity & Average COP from	[76], Sec 3.3
Industrial Excess Heat (TWh)	4.89	Waste heat from industries & Nuclear PP	[57], Sec 10
FD DH Boiler 1	0.042: 0.02: 0.021: 0.9	Fuel Distribution ratio = Coal: Oil: Natural Gas: Biomass. Calculated based on fuel inputs to district heating	[17], Sec 7.2
FD CHP (Heat) Group 3			
FD DH Boiler 3			
FD PP1 G3	0.7:0.2:0.3:8.8	Fuel distribution in Condensing power plant	[17], Sec 3.3
Waste Input G1 (TWh)	4.8083	Waste input to heat only plants in Group 1	[57], Sec 13A
Waste Input G3 (TWh)	10.796	Waste input to CHP plant in Group 3	[57]. Sec 10
Storage			
TES G3 (GWh)	41.667	In 2016, total TES was 150 TJ (41.67 GWh)	[75], Sec 3.1

A.2 Inputs: SWE_2045

Parameter	Value	Description	Reference
Demand			

Electricity demand (TWh)	147.5	Total Demand = 171.71 - Transport demand (17 TWh) & IH - Heat Pumps (7.21 TWh)	[56], Appendix A, Table 3
Electric Heating – IH (TWh)	7.21	Energy Use in Housing sector is 146 TWh. Energy for heating and hot water = .55*146 = 80.3 TWh. DH satisfies 49 TWh. So IH = 31.3 TWh. Use of fossil fuel for heating is replaced by DH or HP. Out of 31.35 TWh, solid bio-fuels fulfil around 9 TWh. Remaining 22.35 TWh is by HP.	[56]
Electricity – Transport (TWh)	17	Transport Sector	[56], Appendix A, Tables 3 & 9
IH – Oil Boiler (TWh)	0	Individual Heat Demand - Energy used for space heating, hot water in households & commercial buildings. Boiler efficiency = 0.9	[56]
IH – NG boiler (TWh)	0		
IH – Biomass boiler (TWh)	10		
DH – Group 1 (TWh)	18.5	Values are distributed between G1 & G3 based on the ratio used in 2019 model. Distribution loss = (62-52)/62 = 0.16	[56]
DH – Group 3 (TWh)	43.5		
DC – Group 3 (TWh)	1.23	No data is available for 2045. Assumption is that demand for cold will not be affected.	[56], [57]
I + V Coal (TWh)	11.2	Industry + Various (agriculture, forestry, fishing, construction, energy sector own use, losses).	[56], Appendix A, Table 6
I + V Oil (TWh)	6.2		
I + V NG (TWh)	5.3		
I + V Biomass (TWh)	53.3		
Transport – Jet Fuel (TWh)	1.7	Aviation Fuel	[56], Appendix A, Table 9
Transport – Diesel (TWh)	25.1	Includes diesel, heavy & light fuel oils	
Transport – Petrol (TWh)	9.1	Gasoline	
Transport – NG (TWh)	0.3	Natural Gas	
Transport – Biofuels (TWh)	9.1	Biofuels	
Supply			
Thermal Boiler G3 (MJ/s)	3500	Same as the input considered for 2019 model, since there is no significant change in DH demand.	[57]
CHP (MW)	6839		[57], Sec 3.0
Condensing PP2 (MW)	1481	Assumed to be same as 2019	[57], Sec 3.0
IC – Nuclear (MW)	3650	Capacity is adjusted based on efficiency (34%) and expected production (28 TWh)	[56]
IC – Hydropower (MW)	16,500	Same as 2019 & 2020 levels.	[57], [56]
IC – Wind (MW)	35,000[11]	Starting from 35 GW to 60 GW at capacity factor = 0.3	[56]
IC – Solar PV (MW)	9900	Capacity factor in 2019 = 0.663 TWh / (690 MW * 8760 h) = 0.11. PV is expected to increase between 9 to 11 TWh.	[17], [56]
Prod. Nuclear (TWh)	28	Production from Nuclear Power Plants	[56]
Prod. Hydropower (TWh)	68	Production from hydroelectric Plants	
Prod. Wind (TWh)	93.55	Production from Wind Power Plants (94 TWh)	
Prod. Solar PV (TWh)	9.71	Production from Solar PV	
ITL Capacity (MW)	11,950	No set targets set. Expected level at 2030.	[19]
Heat Pump (MWe) & COP	400[12], 3.3	Assumed to be at current level.	[76], Ref 5
Industrial Excess Heat (TWh)	5.2	Waste heat from industries & Nuclear PP	[56]
FD DH Boilers 1 & 3	0.022: 0.01: 0: 0.966	Calculated based on fuel inputs to district heating.	[56]
FD CHP (Heat) Group 3			
FD PP1 G3	0.052: 0.0026: 0.026: 0.92	Fuel distribution for Condensing power plant	
Waste Input G1 (TWh)	1.1082	Waste input to heat only plants in Group 1	
Waste Input G3 (TWh)	8.591	Waste input to CHP plant in Group 3	

[11] Wind capacity is varied in all storage technologies and scenarios to determine wind integration at 5% CEEP.
[12] Heat Pump capacity is varied in PtH test caes.

Storage			
TES G3 (GWh)	42[13]	Since there is no significant change in DH demand, TES is assumed to remain the same for No Storage test case.	[56]

A.3 Inputs: NFF_2045

Parameter	Value	Description	Reference
Demand			
Electricity demand (TWh)	188.8	Total Demand = 225 - Transport demand (28.986) & IH - Heat Pumps (7.21 TWh)	[56]
Electric Heating – IH (TWh)	7.21	Demand in Housing & services sector is 146 TWh. Energy for heating and hot water = .55*146 = 80.3. DH = 49 & IH = 31.3 fulfilled by solid bio-fuels (9 TWh) & HP (22.35 TWh)	[56]
Electricity – Transport (TWh)	28.9	Fossil fuels are replaced by electricity. (25 TWh of demand from electrification scenario + 15.945 billion km/year covered by fossil fuel / 4 km/kWh)	
IH – Oil Boiler (TWh)	0	Individual Heat Demand - Energy used for space heating, hot water in households & commercial buildings. Boiler efficiency = 0.9	
IH – NG boiler (TWh)	0		
IH – Biomass boiler (TWh)	10		
DH – Group 1 (TWh)	18.5	Values are distributed between G1 & G3 based on the ratio used in 2019 model. Distribution losses are calculated and found to be (62-52)/62 = 0.16	
DH – Group 3 (TWh)	43.5		
DC – Group 3 (TWh)	1.23	No data available for 2045. Due to uncertainties around developing cooling infrastructure, assumption is that demand for cold will not be affected in the future.	[56], [57]
I + V Biomass (TWh)	93	Demand is fulfilled only by electricity, biomass & hydrogen. (207 = 69 + 45 + 93)	[98]
I + V Hydrogen	45		
Transport – Bio Diesel (TWh)	14.5	Demand is fulfilled by electricity & biofuels. Fossil fuels are assumed to be completely replaced by biofuels.	[56]
Transport – Bio Petrol (TWh)	2.3		
Transport – Biogas (TWh)	0.4		
Supply			
Thermal Boiler G3 (MJ/s)	3500	Same as the input considered for 2019 model, since there is no significant change in DH demand.	[57]
CHP (MW)	6839		[57], Sec 3.0
Condensing PP2 (MW)	1481	Assumed to be same as 2019	[57], Sec 3.0
IC – Nuclear (MW)	3650	Capacity is adjusted in EnergyPLAN based on efficiency (34%) and expected production (28 TWh)	[56]
IC – Hydropower (MW)	16,500	Same as 2019 & 2020 levels.	[57], [56]
IC – Wind (MW)	35,000[14]	Starting from 35 GW to 60 GW at capacity factor = 0.3	[56]
IC – Solar PV (MW)	9900	Capacity factor in 2019 = 0.663 TWh / (690 MW * 8760 h) = 0.11. PV is expected to increase between 9 to 11 TWh.	[17], [56]
Prod. Nuclear (TWh)	28	Production from Nuclear Power Plants	[56]
Prod. Hydropower (TWh)	68	Production from hydroelectric Plants	
Prod. Wind (TWh)	93.55	Production from Wind Power Plants (94 TWh)	
Prod. Solar PV (TWh)	9.7	Production from Solar PV	
ITL Capacity (MW)	11,950	No set targets set. Expected level at 2030.	[19]

[13] TES is varied in simulation strategies for PtH.
[14] Wind capacity is varied in all storage technologies and scenarios to determine wind integration at 5% CEEP.

Heat Pump (MWe) & COP	400, 3.3	Assumed to be at current level.	[76], Ref 5
Industrial Excess Heat (TWh)	5.2	Waste heat from industries & Nuclear PP	[56], Appendix A, Table 5
FD DH Boiler 1	0: 0: 0: 1	Fuel Distribution ratio = Coal: Oil: Natural Gas: Biomass.	[56]
FD CHP (Heat) Group 3			
FD DH Boiler 3			
FD PP1 G3	0: 0: 0: 1	Fuel distribution for Condensing power plant	
Waste Input G1 (TWh)	1.1	Waste input to heat only plants in Group 1	
Waste Input G3 (TWh)	8.591	Waste input to CHP plant in Group 3	
Storage			
TES G3 (GWh)	42	Since there is no significant change in DH demand, TES is assumed to remain the same for No Storage test case.	[56]
Hydrogen Storage (GWh)	115	Maximum hydrogen storage capacity	[98]
Electrolyzer (GWe)	12.6	Maximum electrolyser capacity	

A.4 Inputs: Cost data for SWE_2045 & NFF_2045

Parameter	**Value**			**Description**	**Reference**
General Input					
CO_2 Price (SEK/t CO_2)	4500			Calculated based on yearly average increase of 5.5% from 1991 to 2018.	[122]
Interest (%)	6			Based on discount rates of investment.	[19]
Investment & Fixed OM					
Type of Technology	**Investment (MSEK / unit)**	**Period**	**O & M**	**Description**	**Reference**
Small CHP units	34.5	30	1.68	Estimated costs of biomass-based CHP plants	[19]
Large CHP units	25.5	30	1.49		[19]
Heat Storage	160.82	25	3	Sensible TES cost ranges from 0.1 – 25 USD / kWh. By 2030, the anticipated cost of TES in a PtH system is 15 USD / kWh.	[84]
Waste CHP	9.5	30	0.73	Cogeneration plants	[19]
Heat Pumps, G3	7.2	20	1.8	0.72 million EUR / MW	[123]
DHP Boiler G1	8	30	1.25	Biomass fired boilers in district heating systems.	[19]
Boilers G2 & G3	8	30	1.25		[19]
Large power plants	7	30	0.57	Large gas based condensing PPs	[19]
Nuclear power plants	50	50	1.1	Estimated cost of new nuclear power	[19]
Interconnection	0.4	30	1	700 MW, 300 km HVDC line at 1950 EUR / MW-km + 900 MW, 380 km AC at 250 EUR / MW-km	[98], [19], [124], [125]
Charge El1 Storage	2.3	20	2.5	Considered CAPEX in year 2035, as it aligns with the increased VRES integration in 10 years & reduced costs of PV, Wind PPs & batteries (of storage duration = 4 hours).	[98]
Discharge El1 Storage	2.3	20	2.5		
El Storage	2300	20	2.5		[98]
Wind Power Plant	8	25	2.125		
Wind Offshore	15.3	25	1.503		
Solar PV	5.4	25	2.407		
Hydropower	2.02	40	2	Estimated at 0.5 SEK / kWh	[126], [127]
Electrolyser	4	25	2	CAPEX in 2035	[98]
Hydrogen Storage	286.9	25	2	Incl. hydrogen infrastructure costs at total investment of 3.3 billion	[98]

				EUR for approximately 115 GWh storage	
Individual Boilers	0.66	20	4.11	Biomass boiler for an apartment complex at 170 EUR / kW and Fixed O&M at 7 EUR/kW/year and 2487 MW of max. demand / 6.33 million units (2030)	[128]
Individual heat pumps	0.6	20	1.75	Heat Pump for an apartment complex at 480 EUR / kW (2400 EUR for a 5-kW unit) and Fixed O&M at 8.4 EUR/kW/year and 1888 MW / 14. 9 million units (2030)	[128]
Fuels & Taxes					
*Fuel Price (SEK / GJ) includes world market prices and taxes					
Coal	173.56		Estimated at 930 SEK /ton in 2050 and 1 ton of coal equivalent (29.16 GJ) = 31.9 SEK & Taxes applied at 2022 rate of 0.51 SEK / kWh (as no data was available for 2045) = 141.66		[130], [129]
Fuel Oil	183.6		Crude oil at 112 EUR / BOE (6.1 GJ)		[130], [129]
Diesel	1026.38		Estimated at 36.95 SEK / Litre & 1 L (10 kWh)		[130], [129]
Petrol / Jet Fuel	1020.75		Estimated at 33.44 SEK / Litre & 1 L (9.1 kWh)		
Natural Gas	119.44		Estimated at 430 SEK / MWh in 2050		[130]
Biomass	80.36		Calculated based on yearly average increase of 1.72% of wood chips from 1993 to 2021.		[17]
Nuclear PPs	27.78		100 SEK / MWh corresponds to 27.78 SEK / GJ		[19]
Variable O&M					
Boiler	20		SEK / MWh-heat		
CHP	80		SEK / MWh-electricity		
Condensing PP	15		SEK / MWh-electricity		[19]
GTL M1	20		SEK / MWh-fuel input		
GTL M2	20		SEK / MWh-fuel input		
Electrolyser	0		Variable O&M cost = 0 EUR / MWh		[98]
External Electricity Market					
Multiplication Factor	0.79		Calibrated to get avg. price = 587 SEK / MWh		[130]
Price Elasticity	0.029		SEK / MWh pr. MW. Based on buying patterns of traders in the Nordpool market.		[131]

A.5 Distribution Files

Scenario	Description	File Name	Reference
Reference Model 2019	Hourly Distribution of Electricity demand	SE_2019_Elec_hour.txt	[62]
	Hourly import & export of electricity	SE_2019_import_export_hourly.txt	[62]
	Hourly individual heat demand	SE_2019_district_heating_hourly.txt	[62]
	Hourly DH demand		
	Hourly district cooling demand	SE_Dist_Cooling_2019.txt	[62]
	Hourly electricity demand from transport sector	Hour_US2001_transportation.txt	[121]
	Hourly distribution of nuclear production	SE_2019_Nuclear_hour.txt	[62]
	Hourly distribution of hydro power	SE_2019_water_inflow.txt	[62]
	Hourly wind power distribution	SE_2019_Wind_hourly.txt	[62]
	Hourly PV distribution	SE_2019_Solar_hourly.txt	[62]
SWE_2045 & NFF 2045	Hourly Distribution of Electricity demand	SE_2019_Elec_hour.txt	[62]

	Hourly individual heat demand	SWE_2045_Heatdemand	[131], [132], [133], [134]
	Hourly DH demand		
	Hourly district cooling demand	SE_Dist_Cooling_2019.txt	
	Hourly electricity demand from transport sector	Hour_US2001_transportation.txt	[121]
	Hourly distribution of nuclear production	SE_2019_Nuclear_hour.txt	[62]
	Hourly distribution of hydro power	SE_2019_water_inflow.txt	[62]
	Hourly wind power distribution	SE_2019_Wind_hourly.txt	[62]
	Hourly PV distribution	SE_2019_Solar_hourly.txt	[62]
	Hourly distribution of hydrogen demand	SWE_2045_Heatdemand.txt	[131], [132]