UNIVERSITY OF LJUBLJANA

SCHOOL OF ECONOMICS AND BUSINESS

MASTER'S THESIS

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GREEN TRANSFORMATION: DECARBONISATION PLAN FOR THE SLOVENIAN ELECTRIC POWER SYSTEM AND ITS MACROECONOMIC IMPLICATIONS

Ljubljana, November 2022 IZIDOR OSTAN OŽBOLT

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I am grateful to my girlfriend Iva and my family, especially my mother Nina, sister Hana and father Alen, who stood by my side when I was writing the master's thesis, particularly in difficult moments. I am much obliged to you all for giving me enough time and support to finish my master's thesis.

Content-wise, the guidance and advice from my mentor, dr. Jože P. Damijan, have been essential. The explanations, instructions and data offered by mag. Aleksander Mervar are highly appreciated. I am sincerely thankful to dr. Dejan Paravan, Jan Bohinec and mag. Drago Babič, and everyone else without whom the depth and quality of the master's thesis would have been considerably lower (in alphabetical order): Aleš Donko, Bojan Drol, mag. Klemen Dragaš, dr. Marko Kolenc, dr. Vladimir Malenković, dr. Miloš Markič, Marijan Penšek, Zala Primc, Samo Remec, mag. Uroš Salobir, dr. Jerneja Sedlar, Tina Seršen, Nejc Trampuž and others.

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sl. – Slovene

ACER – (sl. Agencija za sodelovanje energetskih regulatorjev); Agency for the Cooperation of Energy Regulators

aFRR – (sl. avtomatska rezerva za povrnitev frekvence); automatic frequency restoration reserve

BtM – (sl. za števcem); behind the meter

CAN EU – (sl. Evropska akcijska mreža za podnebje); Climate Action Network Europe

CCGT – (sl. plinsko parna elektrarna); combined cycle gas turbine

CCUS – (sl. zajemanje, uporaba in skladiščenje ogljika); carbon capture, utilisation and storage

CHPP– (sl. soproizvodna elektrarna); combined heat and power plant

CO_2 – (sl. ogljikov dioksid); carbon dioxide

CRM – (sl. mehanizem nadomestil za zmogljivost); capacity remuneration mechanism

ČHE Avče – (sl. črpalna hidroelektrarna Avče); pumped storage hydropower plant Avče

ČHE Kozjak – (sl. črpalna hidroelektrarna Kozjak); pumped storage hydropower plant Kozjak

DEM – (sl. Dravske Elektrarne Maribor): Dravske elektrarne Maribor

DOPPS – (sl. Društvo za opazovanje in proučevanje ptic Slovenije); Slovenian Bird Watching and Research Society

DSM – (sl. upravljanje s porabo); demand-side management

EEA – (sl. Evropski emisijski kupon); European Emission Allowance

EBITDA – (sl. dobiček pred obrestmi, davki in amortizacijo); Earnings before interest, taxes, depreciation and amortization

EC – (sl. Evropska komisija); European Commission

EIB – (sl. Evropska investicijska banka); European Investment Bank

ELES – (sl. ELES, sistemski operater prenosnega omrežja); Electricity Transmission System Operator

EPS – (sl. elektroenergetski sistem); electric power system

EU ETS – (sl. Evropski sistem za trgovanje z izpusti); European Union Emission Trading System

EV – (sl. električni avtomobil); electric vehicle

FCR – (sl. rezerva za vzdrževanje frekvence); frequency containment reserve

GDP – (sl. bruto domači proizvod); gross domestic product

GHG emissions – (sl. emisije toplogrednih plinov); greenhouse gas emissions

HPP – (sl. hidroelektrarna); hydropower plant

IEA – (sl. Mednarodna agencija za energijo); International Energy Agency

IFotM – (sl. pred števcem); in front of the meter

IPBES – (sl. Medvladna znanstveno-politična platforma o biotski raznovrstnosti in storitvah ekosistemov); Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services

IPCC – (sl. Medvladni panel za podnebne spremembe); Intergovernmental Panel on Climate Change

IRENA – (sl. Mednarodna agencija za obnovljivo energijo); International Renewable Energy Agency

JEK2 – (sl. druga jedrska elektrarna na lokaciji Krško); second nuclear power plant in Krško

JTF – (sl. Sklad za pravični prehod); Just Transition Fund

LCOE – (sl. izravnani stroški električne energije); levelized cost of electricity

LRF – (sl. linearni faktor zmanjšanja); linear reduction factor

mFRR – (sl. ročna rezerva za povrnitev frekvence); manual frequency restoration reserve

NECP – (sl. Nacionalni energetski in podnebni načrt); National Energy and Climate Plan

NPP – (sl. jedrska elektrarna); nuclear power plant

OCGT – (sl. plinska elektrarna odprtega tipa); open cycle gas turbines

PAC – (sl. skladen s Pariškim sporazumom); Paris Agreement Compatible

PEM electrolyser – (sl. elektrolizer s polimerno elektrolitsko membrano); polymer electrolyte membrane electrolyser

PČHE Rudar – (sl. podzemna črpalna hidroelektrarna Rudar); underground pumped storage hydropower plant Rudar

PSHPP – (sl. črpalna hidroelektrarna); pumped storage hydropower plant

PV – (sl. Premogovnik Velenje); Coal mine Velenje

RES – (sl. obnovljivi viri energije); renewable energy sources

RTH – (sl. Rudnik Trbovlje-Hrastnik); Coalmine Trbovlje–Hrastnik

SAŠA region – (sl. Savinjsko Šaleška regija); Savinjsko Šaleška region

SAZU – (sl. Slovenska Akademija Znanosti in Umetnosti); Slovenian Academy of Sciences and Arts

sHPP – (sl. mala hidroelektrarna); small hydropower plants

SMR – (sl. mali modularni reaktor); small modular reactor

SNG – (sl. sintetični zemeljski plin); synthetic natural gas

SODO – (sl. Sistemski operater distribucijskega omrežja); Electricity Distribution System Operator

SOEC – (sl. reverzibilen trdno oksiden elektrolizer); solid oxide electrolyser cells

SPP – (sl. sončna elektrarna); solar power plant

TEB – (sl. Termoelektrarna Brestnica); Thermal Power Plant Brestnica

TEŠ – (sl. Termoelektrarna Šoštanj); Thermal Power Plant Šoštanj

TEŠ6 – (sl. šesti blok Termoelektrarne Šoštanj); unit 6 at the Thermal Power Plant Šoštanj

TETOL – (sl. termoelektrarna toplarna Ljubljana); combined heat and power plant Ljubljana

UMAR – (sl. Urad Republike Slovenije za makroekonomske analize in razvoj); Institute of Macroeconomic Analysis and Development

UN – (sl. Združeni narodi); United Nations

UPSHPP– (sl. podzemna črpalna hidroelektrarna); underground pumped storage hydropower plant

vRES – (sl. variabilni obnovljivi viri energije); variable renewable energy sources

WACC – (sl. tehtano povprečje stroškov kapitala); weighted average cost of capital

WHO – (sl. Svetovna zdravstvena organizacija); World Health Organisation

WPP – (sl. vetrna elektrarna); wind power plant

INTRODUCTION

Climate change is one of the biggest challenges of our time. In the words of the former president of the World Bank, it is a "fundamental threat to development" and "if we do not confront [it], there will be no hope of ending poverty or boosting shared prosperity" (The World Bank, 2014). To resolve this problem, we need – in the words of the Intergovernmental Panel on Climate Change (IPCC), the United Nations (UN) body for assessing the science related to climate change – "rapid, far-reaching and unprecedented changes in all aspects of society" (Intergovernmental Panel on Climate Change, 2018). Pushed or nudged by public apprehension and stark scientific predictions, public and private agents are ramping up their efforts to tackle climate change and reduce greenhouse gas (GHG) emissions.

In 2015, politicians worldwide negotiated and adopted The Paris Agreement, which enshrined the goal of limiting temperature rise to well below 2°C above pre-industrial levels, with the aim of reaching a 1.5°C increase (United Nations, 2015). Despite global summits, climate mainstreaming and strengthened ambitions, we are not on track to abide by the Paris Agreement. As things stand now, if all climate measures proposed by countries globally and cited in their Nationally Determined Contributions[1] were fulfilled, we would reach a rise of approximately 3.2°C temperatures above pre-industrial levels (United Nations Environment Programme, 2019, p. IX). Since measures are unconditional and, judging by past experience, will not be fully implemented, such an increase is not very likely. Predictions for Slovenia are not encouraging, either – the title of the digital launch of Climate Mirror 2020, a yearly report by the renowned Centre for Energy Efficiency at the Institute Jožef Stefan and its partners that provides an overview of Slovenian climate policies, runs: "More effort needed to control long-term GHG emissions!" (Institut Jožef Stefan, 2020). Thus, there is a considerable gap between political verbiage and the implementation of efficient measures.

Two crucial reasons for such a situation are the lack of a well-founded, precise and interdisciplinary plan, taking into account all relevant perspectives, and the absence of sincere, well-intentioned and factual deliberations of all crucial stakeholders. Most of the actors in the climate arena are frequently entrenched in their beliefs and positions. They hardly try to make an honest effort to listen and understand others' positions, and rarely strive to find common ground. Due to a lack of precise data on job gains and losses caused by green transformation and non-existent unequivocal political support for a genuine just transition for workers and affected communities, workers, their representatives and the general public are sceptical and suspicious of the transition when it comes to efficient measures. The absence of clear data on the total costs of such a plan and its effects on the prices of various goods only make matters worse. As a result, goals and measures are not

[1] Nationally determined contribution is a country's climate plan that should be regularly submitted to the Conference of the Parties, the UN governing body on climate issues. It entails detailed measures that a country intends to implement.

ambitious enough, proposed policies are not realized, and most of the projects face some sort of opposition. Aleksander Mervar, director of ELES, Slovenian electricity transmission system operator, and one of the leading Slovenian experts on electric power systems, recognized the essentiality of addressing this gridlock in his recent article (2021), which he concluded with an appeal to all stakeholders: "A lot of work needs to be done and compromises need to be made by employees and experts in the electric power sector, non-governmental organizations and executive and legislative branches of the government […] Above all, we deserve much more truth in mutual communication and not false and deceived verbiage" (Mervar, 2021). Additionally, one-sided expertise and views will not suffice; what we require is interdisciplinary knowledge (Mervar, 2021).

Such a standstill has happened in the electric power sector in Slovenia. No major decisions have been made on an effective decarbonisation path of the Slovenian electric power system; most energy projects face some sort of public opposition from local communities, nature conservationists or trade unions. Potential job losses and gains caused by the decarbonisation of the electric power system are either not assessed or poorly communicated; a just transition that would benefit workers and communities is mainly still an empty word and sensible decarbonisation economic plans are at best rare. Such a situation is even more worrisome due to three factors. First, electricity and heat generation represented 29% of all GHG emissions in Slovenia in 2019, behind only the transportation sector with 33% of emissions (Đorić, Petelin Visočnik, Janša & Česen, 2021, p. 12). Second, decarbonisation of electric power system should be carried out faster, and the timeline should be more ambitious as its technological, governing, societal, economic, and other challenges are (strange as it may sound) less burdensome than in, for example, the transportation and industry sectors. Specifically, it is easier to phase out fossil fuels in the electric power system than substitute all of the internal combustion engine vehicles owned by Slovenian households and set up a whole new charging network. Third, as transportation, heating, industry and other sectors will undergo a rapid electrification in the future, the electric power system will play a central role in decarbonisation efforts (D'Aprile et al., 2020). Therefore, the motivation to contribute to the resolution of the expressed described gridlock in such a crucial sector is clear, and the objective of my master's thesis stems from it – to work on a realistic, well-founded and holistic decarbonisation plan of the Slovenian electric power system, which could at least partly address the shortcomings described above, provide the initial, middle ground for future deliberations with various stakeholders, and initiate, spearhead and direct more interdisciplinary scientific research in the climate- and energy-related fields. It is deemed that the plan should consider five main pillars if it is to be satisfactory for all crucial actors: security and reliability of supply; economics of electricity generation and the electric power system; social justice of energy transition; nature conservation; and compliance with the Paris Agreement.

In the master's thesis, I will examine and evaluate the following two hypotheses:

1. There exists at least one viable decarbonisation path for the Slovenian electric power system that is in line with the five main pillars: reliability and security of supply; the economics of electricity generation; social justice of the transition; nature conservation; and compliance with the Paris Agreement.
2. The proposed decarbonisation plan is economically feasible in the sense that coal phase-out will happen when comparable power plants reach lower cost prices; future weighted electricity cost prices will increase marginally, at worst, compared to 2021 and be in line with the SAZU study; estimated future profits before tax of the whole electric power system will, at worst, stay the same compared to 2021; projected total investments will be viable throughout the 2022–2040 period and comparable to the SAZU study; and lastly, predicted yearly investments will be in line with other analyses and present a reasonable and manageable rise compared to the past expenditures.

The first hypothesis will be confirmed or rejected by using the methodological framework of five criteria. It will be presented in depth in the first chapter, whereas here, the summary of the principal conditions for all five pillars will be given.

Compliance with the Paris agreement will be assessed by evaluating the proposed scenario at reaching net-zero GHG emissions by approximately 2035. The life-cycle greenhouse gas emissions of various energy sources (Ritchie (2020) building upon the studies prepared by IPCC (2014) and Pehl et al. (2017)) will be employed, taking into account all the indirect and direct emissions from construction and operation to upstream GHG emissions.

The reliability and security of supply will be tested in various ways. For reliability, the required amount and envisioned amount of automatic frequency restoration reserve and positive manual frequency restoration reserve of the proposed scenario will be estimated by using ELES's methodology (internal ELES document). If the plan at least reaches the required level, the scenario will be deemed reliable. For the security of supply, proposed strategic reserves will be juxtaposed to the required installed capacity using Mervar's methodological approach (correspondence with Mervar), envisioned coverage of peak load will be compared with past data and the anticipated development of cross-zonal transmission capacities (CZC), and expected yearly import dependence will be measured against the import threshold of 25% of annual consumption deemed acceptable by the National Energy and Climate Plan (NECP) (Žerdin et al., 2021, p. 195). It will also be evaluated if predicted technologies can resolve the challenge of surplus solar power output in the warmer months. Additionally, the indicated investments in the power grid will be compared to the estimations made by ELES (2020) and Electricity Distribution System Operator (SODO) (2020), hydrogen storage requirements will be evaluated and discussed with an expert from the Geological Survey of Slovenia, and future electricity generation profile will be analysed against the current structure considered highly favourable by experts, where neither energy source nor power plant captures more than a 40% share.

In terms of the economics of the electric power system, five conditions will be pursued. First, the coal phase-out date should be proposed in such a way that TEŠ would shut down when comparable power plants reach lower cost prices. Second, as for construction, only economically sensible and commercially available technologies should be proposed based on the data from the most prominent international or Slovenian institutions, such as International Energy Agency (IEA), International Renewable Energy Agency (IRENA), Bloomberg NEF and Institute Jožef Stefan. Additionally, where various types of the same technology are available (e.g. alkaline and PEM electrolysers), types with lower investment costs should be preferred. To test the hypothesis, the weighted electricity cost prices, estimated by using an upgraded model from German think tank Agora Energiewende (Fürstenwerth, 2014), should be at least comparable to the values from the decarbonisation plan prepared by electrical engineers, economists, biologists and others within the Slovenian Academy of Sciences and Arts (SAZU) (SAZU, 2022). This study presents the most coherent and in-depth publicly available scenario in Slovenia. Additionally, the weighted electricity cost price increase should be negligible, thus reaching 5% at most in 2040 compared to 2021. Third, cumulative investment costs, calculated by utilising data from IEA, IRENA, Bloomberg NEF, Institute Jožef Stefan and other high-profile institutions, should be in line with the SAZU study. Fourth, predicted yearly average investment costs should be comparable to the assessment by the European Commission (EC) (Darvas & Wolff, 2021) and present a reasonable and manageable rise compared to past expenditures, based on the data from the Fiscal Council, Institute of Macroeconomic Analysis and Development (UMAR), European Commission, United Nations Industrial Development Organization, Global Green Growth Institute and others. Fifth, estimated future profits before tax of the whole electric power system will be calculated for the years 2021, 2030 and 2040. To confirm the hypothesis, values from 2030 and 2040 should be equal to or higher than those from 2021.

The pillar of social justice touches upon global, national and local elements. Regarding the international level, the accelerated decarbonisation of Slovenia and other so-called developed countries must give the so-called developing countries room to thrive. Therefore, the hypothesis will be accepted if the proposed scenario complies with the Paris agreement (first pillar). On the national level, the installed capacity of community-based and household solar power plants should cover at least a fifth of all installed solar capacities, and the change in weighted electricity cost price should reach up to a 5% rise for the hypothesis to be accepted. At the local level, the focus should be on the just transition in the Šaleška valley and the Zasavje region. The hypothesis will only be confirmed if a just transition plan is drawn up for the Šaleška valley based on the best available data (Deloitte, 2021; Časnik Finance, 2021; Razvojna agencija Savinjsko-Šaleške regije, 2021; Pirc, 2021; correspondence with a former RTH employee and various experts) and substantial investments in the Zasavje region are proposed.

The nature conservation pillar will be evaluated through different lenses. The hypothesis will be accepted if three conditions are met. First, only low-carbon energy sources with no or minimal impact on biodiversity will be chosen. The study from Luderer and coauthors (2019) published in the renowned scientific journal Nature Communication calculating the life-cycle effects of various power stations on nature and biodiversity will be utilised as a guiding principle. Second, where available (Bordjan, Jančar & Mihelič, 2012; Aquarius, 2015a; Aquarius, 2015b), maps delineating GO-TO areas outside the biodiversity-rich environment will be used for locating power plants in non-contested areas. Third, the prevalence of the public interest of electricity generation over nature conservation, defined in the Nature Conservation Act (1999), will not be applied.

To conclude, the first general hypothesis will be confirmed if all the above features align with the stated conditions.

To assess the second hypothesis, five conditions already presented in the economics part of the first hypothesis will be evaluated. If all conditions are met, the second hypothesis will be confirmed.

Besides methodological issues, choosing the most reliable data will play an essential part. Where possible, Slovenian data will be employed. In other cases, data from reliable, well-founded and scientific sources, excluding organisations with a clear interest in a particular energy source, will be utilised. To complete my master's thesis, I have been in contact with approximately 20 experts from various scientific fields and used almost 300 sources. The plan would be unimaginably narrower without some thorough studies on the decarbonisation of the Slovenian electric power system written before and amidst the preparation of the master's thesis – Babič's and Damijan's proposal (2020) and Mervar's plan (2021), both published in the renowned Sobotna priloga, a weekly supplement of the daily newspaper Delo, the scenario prepared by energy company GEN-I and Slovenian Transmission System Operator ELES within Consortium for the Promotion and Acceleration of Green Transformation of Slovenian Energy System with the Aim of Decarbonisation of Slovenia by 2050, and last but not least, the plan proposed by electrical engineers, economists, biologists and others within Slovenian Academy of Sciences and Arts (SAZU, 2022).

Despite the essentiality of the plans above and other sources, my scenario inherently contains limitations stemming from, on the one hand, the fact that preparing a comprehensive five-pillared decarbonisation plan requires a group of experts from various scientific fields and, on the other, that my task and objective have been seminal as, to the best of my knowledge, a plan that would address all five pillars and propose a viable, working compromise is yet to be outlined.

The master's thesis was written based on the mentioned and additional sources. Its structure is as follows: in the first part of the master's thesis, I sketch the five criteria through which different power-generating technologies are assessed and chosen. In the following chapter, I present existing electricity generation and explain current and future direct and indirect electricity consumption and peak load. In the third section, I provide a detailed timeline of coal phase-out in Slovenia with a focus on a restructuring plan of Thermal Power Plant Šoštanj (TEŠ) and a just transition in Šaleška valley. After delineating the schedule for shutting down coal-fired power plants in Slovenia, in the fourth part, I propose a precise deployment plan of various energy sources, technologies and network upgrades to decarbonise the electric power system in a technically safe manner. The following energy sources or technologies are assessed: solar, wind, small and big hydropower plant, (underground) pumped storage hydropower stations, biomass, biogas, natural gas, hydrogen, synthetic natural gas (SNG)[2], batteries, demand side management and nuclear energy. Their role and future installed capacity are determined by evaluating their appropriateness in terms of five pillars: reliability and security of supply; economics; social justice; nature conservation; and role in the reduction of GHG emissions. Related investment costs of each energy source or technology are estimated. In the fifth chapter, I consider the system-wide aspects of the suggested decarbonisation plan: technologies and associated investment costs for coping with excess (solar) power output during warmer months; future role and prospects of demand-side management, battery storage, hydrogen and synthetic natural gas; capacities of new strategic reserves required for future security and adequacy of the electricity supply; location and investment costs of hydrogen storage site in Petišovci, Paka, Ratka and Lovaszi depleted gas reservoirs; coverage of future peak load; requirements of ancillary services, especially automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR); and lastly, a detailed decarbonisation program for gas-fired power stations by using hydrogen and synthetic natural gas. In the sixth chapter, I present the energy balance and structure of electricity generation in the projected development of the electric power system, and calculate import dependency and pace of decarbonisation. Additionally, I tackle diverse economic themes: weighted cost prices throughout the 2022-2040 period; estimated profits before tax of the whole electric power system in 2021, 2030 and 2040; total investment costs per year and throughout the observed era; total investments as a share of GDP; and lastly, proposed annual expenditures compared to past investments. In the conclusion, the summary and discussion of findings and further research challenges are presented.

1 FIVE CRITERIA FOR DETERMINING THE PLAN OF FUTURE ELECTRIC POWER SYSTEM DEVELOPMENT

In this chapter I will provide the background why I chose a five-pillar approach and how each of them could be defined. This methodology will be essential to provide a context and thus direct and define a scenario of future electric power system development. When talking

[2] Synthetic natural gas (SNG) describes various natural gas alternatives that are close to natural gas in composition and properties. It can be generated from multiple energy sources. In the master's thesis, I focus on SNG synthesized using renewable energy.

about “a decision-making process of choosing the most suitable technologies for electricity production”, Mervar (2019b, p. 8) postulates the need to find a “sustainable balance between technology, ecology, economics and the effects on the wealth of the nation”, but he does not clarify these notions. The ecological pillar, for instance, could be easily divided into two parts that are not always in line yet constitute the core of the ecological aspect: timely climate change mitigation and nature conservation. The similar classification could also be derived from the World Energy Trilemma Index (World Energy Council, 2020), the most famous and comprehensive comparative ranking of the energy systems in different countries. The index estimates a country’s performance across three dimensions: energy security, energy equity and environmental sustainability. The first focuses on reliability, security, robustness and resilience of national electric power systems to cover current and future energy needs; the second on accessibility and affordability of an adequate amount of energy for households and commercial users; and the third on the impacts and averted harm that the current and future national energy supply will cause to the environment, nature, health and climate change. Energy equity could be split into social justice and economics of electricity generation, and environmental sustainability into timely climate change mitigation and nature conservation. I thus propose five criteria for assessing and determining a detailed plan for the future development of the electric power system contingent upon Mervar’s proposal and the Energy Trilemma Index: reliability and security of supply; the economics of electricity generation and the electric power system; social justice of energy transition; nature conservation; and compliance with the Paris Agreement. Table 1 provides a summary of five criteria described in-depth in the following subchapters.

Table 1: Five criteria for assessing and determining a viable plan for the development of the electric power system

CRITERIA	CONDITIONS
COMPLIANCE WITH THE PARIS AGREEMENT	- Net-zero GHG emissions in electric power system around 2035 (to leave some room for the harder-to-abate sector to decarbonise and reach society-wide net-zero GHG emissions shortly after 2040).
RELIABILITY AND SECURITY OF SUPPLY	Reliability of supply: - sufficient automatic frequency restoration reserve (aFRR) compared to required values - (positive) manual frequency restoration reserve (mFRR) compared to required values Security of supply: - adequate strategic reserves set side by side with required level - sensible coverage of peak load compared to past data and the anticipated development of cross-zonal transmission capacities - yearly import dependence substantially below 25% of annual consumption deemed acceptable by the NECP - resolved surplus (solar) power output in the warmer months Additional robustness: - adequate transmission and distribution networks compared to values proposed by ELES (2020) and SODO (2020) - sufficient seasonal hydrogen storage facilities - a balanced future generation profile, where neither energy source nor power plant captures more than a 40% share
ECONOMICS OF ELECTRIC POWER SYSTEM	Cost-effective coal phase-out: - stop coal usage in TEŠ when sensible alternatives reach lower cost prices - minimisation of state aid for TEŠ New energy sources with reasonable cost prices and system costs and types of the same technology with lower investment costs: - estimated weighted electricity cost prices in line with the ones from the SAZU study - up to a 5% increase in weighted cost prices in 2040 compared to 2021 - predicted cumulative investment costs comparable to the ones from the SAZU study (2022) - predicted yearly average investment costs in line with the assessment by the EC (Darvas & Wolff, 2021) - manageable rise in predicted yearly average investment costs compared to past expenditures - estimated future profits before tax of the whole electric power system in 2030 and 2040 equal to or higher than those from 2021
SOCIAL JUSTICE	Global: - accelerated decarbonisation in the so-called developed world (i.e. net-zero GHG emissions in the electric power system by around 2035) to leave room for the so-called developing countries to thrive. National: - up to a 5% increase in weighted electricity cost prices in 2040 compared to 2021 - a fifth of all installed solar capacity owned by households or communities (expansion of energy democracy) Local: - just transition plan in the Šaleška valley - investments in the Zasavje region

NATURE CONSERVATION	- Low-carbon energy sources with no or minimal impact on biodiversity, based on life-cycle analysis - Power plants outside the biodiversity-rich environment, using GO-TO areas - No prevalence of the public interest of electricity generation over nature conservation

Source: own work.

1.1 Compliance with the Paris Agreement or timely climate change mitigation

Compliance with the Paris Agreement or timely climate change mitigation represents the most obvious aspect of the plan. Although it is hard to define the actual pace of decarbonizing the Slovenian electric power system, the Paris Agreement (2015), the most important and overarching global climate legal framework, signed by 196 countries, provides central orientation. In Article 2, it states that the objective of the signatory countries is to limit the "increase in the global average temperature to well below 2°C above pre-industrial levels" and pursue "efforts to limit the temperature increase to 1.5°C above pre-industrial levels". This goal "will be implemented to reflect equity and the principle of common but differentiated responsibilities and respective capabilities, in the light of different national circumstances". Article 4 reiterates the same notion – decarbonisation measures of each country should "reflect its highest possible ambition, reflecting its common but differentiated responsibilities and respective capabilities, in the light of different national circumstances". Thus, "developed country Parties should continue taking the lead", whereas "peaking will take longer for developing country Parties" (United Nations, 2015). The Paris Agreement does not only set the goal of limiting the temperature rise to a maximum of 2°C with the aim of reaching a change of 1.5°C compared to pre-industrial levels, but also brings to the forefront the concepts of justice, equity, equality and common but differentiated responsibilities and capabilities in causing, mitigating and adapting to climate change. The essentiality of these conceptions dates back to the founding document of UN climate change talks, the United Nations Framework Convention on Climate Change (United Nations, 1992), where the principle of common but differentiated responsibilities and capabilities was introduced and the historical responsibility of the developed world in causing the climate crisis was recognized and emphasized. Nevertheless, how can these notions and objectives be concretized? Excluding questionable and unproven negative emissions technologies, Anderson, Broderick and Stoddard (2020) calculate that developed countries should reduce GHG emissions by 11% per year to comply with the Paris Agreement from 2020 onwards. That would mean that the world has 66–100% chance of limiting the temperature below 2°C and a 33–66% chance to cap the temperature rise to a maximum of 1.5°C compared to the 1850–1900 baseline (Anderson Broderick & Stoddard. 2020, p. 6). Since authors incorporate the equity principle from the Paris Agreement into their equation, the proposed number is higher than the 7.6% average reduction target proposed by the United Nations Environment Programme (UNEP) (2019, p. X). The objective translates to a 68% reduction of Slovenian GHG emissions by the end of 2030, 83% by 2035 and 90% by 2040, all relative to 2020, not accounting for carbon sinks. This is much faster than the current Slovenian intentions of 22% and 60% reductions by 2030 and 2040 relative to 2020, respectively, and of reaching net-zero carbon emissions by 2050 (Portal Energetika, 2019).

What are the implications for the electric power system in Slovenia? The sector should experience 68% reduction of GHG emissions by the end of 2030 and reach net-zero GHG emissions around 2035. Bear in mind that technological, governance, societal, economic and other decarbonisation challenges are more convoluted in industry, transportation and agriculture than in the energy sector. Additionally, in the context of a society-wide electrification expected to take place in the future, decarbonisation of the electricity sector would lower emissions throughout society and across sectors. Fossil fuels phase-out in the electric power system considerably before 2040 combined with carbon sinks would thus leave some room (i.e. few additional years) for the harder-to-abate sectors to figure out their most sensible decarbonisation paths.

Moreover, the data gathered by Ritchie (2020), which builds upon the studies written by IPCC (2014) and Pehl et al. (2017) and assesses the life-cycle greenhouse gas emissions of various energy sources, thus considering all the indirect and direct emissions, from construction and operation to upstream GHG emissions, provides a sensible orientation as to which energy sources should be used in the future to minimize carbon footprint. The results are shown in Table 2.

Table 2: Life-cycle GHG emissions of various energy sources (tCO2-eq./GWh)

LIFE-CYCLE GHG EMISSIONS BY ENERGY SOURCES (tonnes of CO_2-eq./GWh)	
COAL	820
OIL	720
NATURAL GAS	490
BIOMASS	151
HYDROPOWER	34
SOLAR ENERGY	5
WIND ENERGY	4
NUCLEAR ENERGY	3

Source: Ritchie (2020).

1.2 Reliability and security of supply

Reliability and security of supply need to be considered as part of the technical aspects of the decarbonisation plan. Even though these two concepts are commonly perceived as interchangeable, they are qualitatively different. Additionally, emphasis will also be given on the additional robustness of the system, namely investments in the electricity network, seasonal hydrogen storage and balanced generation profile.

In Slovenia, reliable supply is ensured by ELES, the Slovenian electricity transmission system operator (TSO), primarily through ancillary services. The master's thesis focuses on two vital such services – automatic frequency restoration reserve (aFRR) and (positive) manual frequency restoration reserve (mFRR). The grid in European Union operates at the frequency of 50 Hz and can fluctuate for a maximum of ±0.2% without severe consequences. To assure a stable grid frequency, TSO manages the frequency containment reserve (FCR), aFRR and mFRR. When frequency alternation occurs, the FCR, also called primary control reserve, automatically responds within seconds and restores the balance between supply and demand. In Slovenia, every power plant connected to the transmission grid is obliged to procure FCR free of charge. If the deviation endures, the aFRR, also known as secondary control reserve, is automatically activated through the central regulator. It starts operating simultaneously with the declining FCR after 30 seconds. Since the electric power system experiences surges and drops in demand and supply, both a positive and a negative balancing capacity of aFRR is required. In Slovenia, aFFR is currently provided by hydropower plants, thermal power plants and batteries in Jesenice and Kidričevo. If the disturbances in the system are long lasting, mFRR, also known as tertiary control reserve, is activated. It is fully deployable after 12.5 minutes and is activated manually by ELES. Positive and negative balancing capacities of mFRR are needed. According to the European legal framework, the capacity of mFRR must equal the largest generation and load unit within the operating block. Since the operating block consists of Slovenia, Croatia and Bosnia and Hercegovina (ELES, 2020, pp. 97–98), these three countries cover the installed capacities of selected units collectively and thus individually bear smaller shares. For example, positive mFRR in Slovenia totals 250 MW (covered mainly by open cycle gas turbines in Brestanica) even though the largest unit in the operating block is the Nuclear power plant Krško. As decarbonisation, with its termination of coal-fired power plants and expansion of variable renewable energy sources (RES), will have ample effects on reliability of supply, the adequacy of future automatic and (positive) manual frequency restoration reserves will be considered in the master's thesis. To be concrete and focus on the subject at hand, the required amounts and envisioned amounts of automatic frequency restoration reserve and positive manual frequency restoration reserve of the proposed scenario will be calculated using ELES's methodology (internal ELES document). If envisioned amounts are at least in line with the required values, the scenario will be perceived as reliable.

In the master's thesis, four topics of security of supply will be addressed: strategic reserves; coverage of peak load; yearly import dependence; and tackling the surplus (solar) power output during warmer months. Security of supply is ensured by balancing groups (and indirectly the executive breach of the government in case of untenable conditions).

First, as electricity generation is becoming more and more volatile and coal-fired power plants independent of the weather are shutting down, Europe is going to experience problems with the adequacy and security of electricity supply if nothing is done to counteract such developments (Medved, Bajec Omahen, Pantoš & Gubina, 2015; Mervar, 2014, pp. 108–

114; Volfrand, 2021). In response, strategic reserves, i.e. flexible, fast-responsive power plants assuring an adequate energy supply when required, have been gaining ground. Such newly constructed and preserved power plants, which stay partly or fully in reserve, are activated mainly in difficult times. Their function is mostly to provide additional electricity during peak load periods in the morning and evening hours of colder months and to assure flexible support for intermittent RES. They are constructed and managed by energy suppliers, dispatched by the TSO and shaped by ministry officials (and politicians) who define the conditions for their construction and operation. The proposed capacity of strategic reserves will be addressed in the following chapters. It will be compared with the required installed capacity using Mervar's methodological approach (correspondence with Mervar).

Second, an electric power system is not designed to cover the average load on a typical day but to secure an adequate supply to meet peak load. Peak load is defined as the "maximum value of load during a given period of time, e.g. a day, a month, a year" (Slovenski komite eletroenergetikov, 2009, p. 27) and on a yearly basis occurs during the evening hours of the winter months, mainly in January (ELES, 2020, p. 36). For this reason, I believe it is of the highest importance that the master's thesis include a proposition on how to develop an electric power system capable of matching future peak load. This proposal will be placed side by side with past data and the expected development of CZC. Imports being in line or below past values and substantially below anticipated CZCs will make the scenario perceived as secure.

Third, excessive annual import dependence, especially with no adequate strategic reserves, can pose a grave threat to the security of supply. Admissible imports that could realistically be envisioned and would not pose an extreme threat to the system are assumed to amount to a quarter of yearly electricity consumption, as proposed by NECP (Žerdin et al., 2021, p. 195). This value will provide the background against which the annual import dependency will be considered. Nevertheless, to stay on the safe side and give the system some additional robustness, import dependency significantly below the quarter of yearly electricity consumption should be strived for.

Fourth, during warmer months, large installed capacities of solar power plants will cause great havoc to the system if various technologies suited for tackling this problem are not in place. Thus, in the master's thesis, I will propose and delineate the deployment of different technologies, which could effectively reduce, shift or store excess power output and thus preserve the system's stability. It will be evaluated whether the predicted technologies can resolve the challenge of surplus solar power output in the warmer months.

Finally, every serious plan should also focus on transmission and distribution networks, seasonal hydrogen storage facilities and a balanced future generation profile, as these will ensure additional robustness of the system. Thus, the indicated investments in the power grid will be compared to the estimations made by ELES (2020) and SODO (2020), hydrogen storage requirements will be evaluated and discussed with an expert from the Geological

Survey of Slovenia, and future electricity generation profile will be analysed against the current structure considered highly favourable by experts, where neither energy source nor power plant captures more than a 40% share.

1.3 Economics of electricity generation and electric power system

Electricity prices represent an important input for various businesses, especially energy-intensive industries, and determine the well-being of households, particularly poor ones. Energy companies also contribute greatly to the national GDP, provide the shareholders with dividends and employ a relatively large number of workers. The economics pillar is addressed by considering three topics: cost-effective coal phase-out; choosing energy sources with reasonable cost prices and system costs; and selecting types of the same technology with lower investment (as well as operation and maintenance) costs. First, economically viable coal phase-out should minimize the size of potential state aid and replace coal-fired power plants with comparable power stations when they reach the same or lower cost prices than TEŠ. Second, energy sources with moderate cost prices and system costs should be proposed to reduce system-wide investment costs and weighted cost price of the whole electric power system. Third, types of the same technology with lower investment costs and cost prices should be chosen, for example, utility-scale solar power plants instead of smaller ones or alkaline electrolysers rather than PEM ones.

Stemming from all three tenets, five conditions arise. First, the coal phase-out date should be implemented in such a way that TEŠ would shut down when comparable power plants reach lower cost prices. Second, the weighted electricity cost prices should be at least similar to the values from the SAZU scenario (SAZU, 2022). Additionally, the weighted electricity cost price increase should be negligible, thus reaching 5% at most in 2040 compared to 2021. Third, cumulative investment costs should be in line with the SAZU study. Fourth, predicted yearly average investment costs should be equivalent to the assessment by the European Commission and present a manageable rise compared to past expenditures. Fifth, estimated future profits before tax of the whole electric power system in 2030 and 2040 should be equal to or higher than those from 2021.

1.4 Social justice

Social aspects of the decarbonisation plan can be divided into the global, national and local level.

On the global level, almost all costs of the climate crisis are borne by the so-called developing and underdeveloped world (DARA & Climate Vulnerable Forum, 2012). As these countries' emissions represent only a negligible fraction of global historical GHG emissions, the developed world should accelerate its decarbonisation efforts and leave room for other countries to develop. The aspect of GHG emissions is addressed under the climate pillar. Other global social aspects (e.g. unequal exchange between the centre and the periphery of the capitalist world system, exploitation of workers in the south to the benefit of northern countries) haven't been tackled, even though they are of great importance.

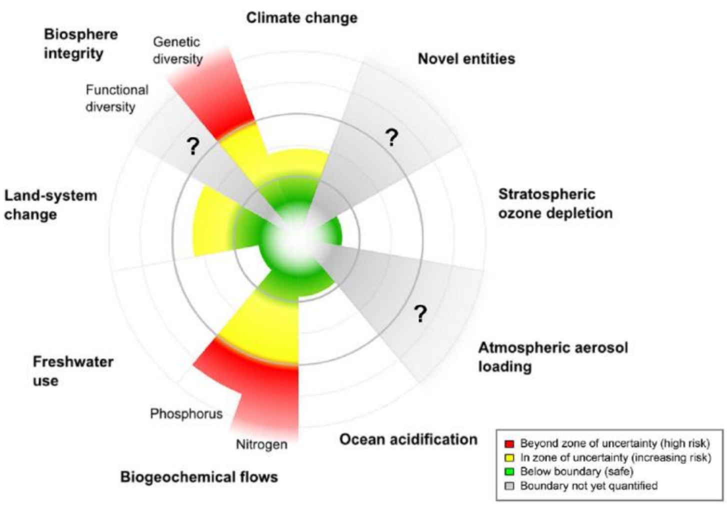
On the national level, the social pillar includes two aspects. First, since low-carbon investments could potentially increase electricity prices with detrimental consequences primarily for poor households, technologies with lower cost prices should be chosen and measures to tackle energy poverty implemented. Concretizing the latter is beyond the scope of my master's thesis. However, I will focus on different costs of energy sources and propose technologies with lower cost prices that minimize potential increases in electricity prices. In the final chapter, I will also calculate the weighted cost prices from 2021 to 2040. Up to a 5% rise is deemed acceptable. The second aspect is dedicated to expanding energy democracy and community energy in Slovenia, where households, communities, local councils and small and medium companies could play a more prominent role in the future electric power system. Such development would not only bring numerous economic and climate benefits (Pollin, 2012), but would also empower people, make communities more cohesive and resilient, open new ways of political participation and contribute to building a new socio-ecological society. Thus, the goal is that a fifth of all installed solar capacities are owned by households or communities.

Lastly, on a local level, the extraction of fossil fuels and their use in thermal power plants require a relatively large mass of workers in one location. Even more, both processes are frequently located on the same spot and significantly determine the developmental path of the whole region. That is the case of the Šaleška valley, where Coal mine Velenje (PV), Thermal power plant Šoštanj and Gorenje generate 70% of total local revenues (Deloitte, 2021, p. 8) and where PV and TEŠ combined employed approximately 1,470 workers in 2020 (Žerdin et al., 2021, p. 52). To ensure a just transition, prevent social, economic and other degradation of the affected region and accelerate the decarbonisation process (by avoiding a potential conflict with trade unions and representatives of affected regions), a special focus should be given to coal regions, namely the Šaleška valley and the Zasavje region, which still bears the consequences of the transition. The importance of a just transition for coal regions has been recognized by the European Union (European Commission, n. d.) and the Slovenian government (Deloitte, 2021). More concretely, a just transition plan for the Šaleška valley should be prepared based on the best available data (Deloitte, 2021; Časnik Finance, 2021; Razvojna agencija Savinjsko-Šaleške regije, 2021; Pirc, 2021; correspondence with a former RTH employee and various experts) and significant investments in the Zasavje region should be envisioned. To sum up, global, national and regional social aspects should be taken into account to ensure a socially just decarbonisation path of the Slovenian electric power system.

1.5 Nature conservation

About a decade ago, a group of scientists, including a few Nobel laureates, introduced the concept of a planetary boundary (Rockström et al., 2009). Society is bound by nine planetary limits (biosphere integrity, climate change, novel entities, stratospheric ozone depletion, atmospheric aerosol loading, ocean acidification, biogeochemical flows, freshwater use, land-system change), which – if not surpassed – provide humanity with a safe operating space to thrive. Alternatively, in a rough economic language, natural capital provides ecosystem services free of charge to humanity. If any boundary is crossed, society enters a zone of uncertainty where each additional negative step can bring about cascading ramifications across the entire system. As can be observed in Figure 1 (Steffen et al., 2015, p. 6), humankind has already passed four of nine boundaries, and the situation is getting worse in most of these aspects. Two overarching boundaries, which affect, permeate and reinforce all others, are climate change and biosphere integrity. In terms of climate change, humanity is situated above the boundary, in the zone of uncertainty, and the risk keeps increasing. As for biosphere integrity, we are well above the planetary boundary and the zone of uncertainty, in the high-risk area.

Figure 1: The current status of the control variables for seven of the nine planetary boundaries



Source: Steffen et al. (2015).

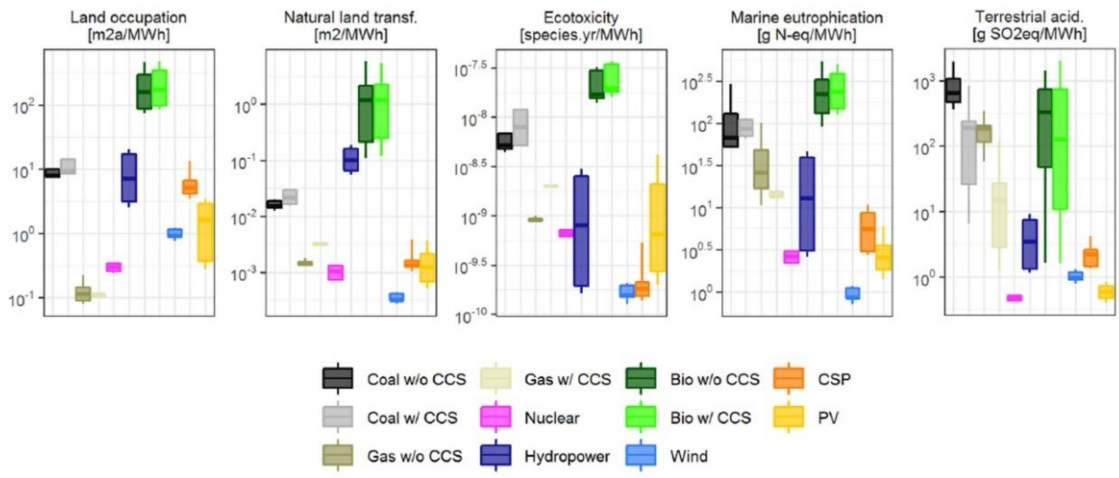
The dire state of biodiversity has been underlined in the recent findings of the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES), the United Nations body equivalent to the more famous IPCC (Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services, 2019). Biodiversity and thriving ecosystems are also strongly interconnected with climate mitigation (i.e. storage of CO_2 emissions by forests) and climate adaptation (i.e. flourishing ecosystems protect, tame and reduce the severity of climate change-induced natural disasters). Based on such linkages, a growing number of scientists are calling for natural climate solutions, where conserving and extending ecosystems goes hand in hand with mitigating climate change and adapting to a new climate reality (Griscom, 2017). However, some decarbonisation interventions are bound to have a negative impact on nature, which holds true for some projects, technologies and energy sources in the realm of electric power systems.

Low-carbon energy sources do not necessarily mean a low impact on nature and biodiversity. This has been recognized on the EU level through the “do no significant harm” principle enshrined in the Recovery and Resilience Facility Regulation (European Commission, 2021b) and the forthcoming EU Taxonomy (EU Technical Expert Group on Sustainable Finance, 2020), which allow and support energy projects with no or minimal impact on nature. The same holds at the national level, where the Strategic Environmental Impact Assessment of National Energy and Climate Plan ascertained that without the completed prevalence of public interest unequivocally permitting the construction proposed hydropower plants on the Sava should be excluded from the NECP due to their negative impacts on biodiversity (Vončina et al., 2020, p. XX). What is more, in the EU Biodiversity Strategy for 2030, for example, the EC demands that a minimum of 25,000 km of European rivers be renaturalised into their natural, free-flowing state (European Commission, 2020, p. 23).

The reasoning above is predominantly anthropocentric, i.e. conserving nature for the sake of humanity, whereas a biocentric one is equally important. The living world (not natural capital), from otters and vultures to lichens and fungus, inhabits our common planet and wanders around freely, and humans have no right to worsen their living conditions, if such actions are not existentially necessary. Such a shift from an anthropocentric to a more biocentric paradigm also presents a prerequisite for achieving systemic changes and reaching the long-term goal – a good life for all within planetary boundaries (i.e. living within the doughnut) (Raworth, 2017).

Thus, three conditions can be defined. First, low-carbon energy sources with no or minimal impact on biodiversity should be chosen. The study by Luderer al. (2019), published in the renowned scientific journal Nature Communication, provides a sensible orientation with presumably the most in-depth and recent figures for various effects of different energy sources. As authors take into account life-cycle assessment, the data include the impacts caused by all the stages of a power plant, from raw material extraction for the construction to the decommissioning. Five impact channels are assessed regarding the ecosystem damage: land occupation, natural land transformation, ecotoxicity, marine eutrophication, and terrestrial acidification. The results are summarised in Figure 2, where boxplots indicate median and interquartile ranges and whiskers in the 10–90% ranges. Second, where possible (Bordjan, Jančar & Mihelič, 2012; Aquarius, 2015a; Aquarius, 2015b), appropriate siting locations (so-called GO-TO zones), which would cause no or minimal impact on nature, and exclusion zones (so-called NO-GO zones), where siting would be forbidden, need to be used when assessing the biodiversity-friendly potential of various energy sources in Slovenia. Third, options such as the prevalence of the public interest of electricity generation over the public interest of preserving nature, included in the Nature Conservation Act (1999), should not be considered.

Figure 2: Per unit life-cycle impacts of various power stations on nature and biodiversity



Adapted from Luderer et al. (2019).

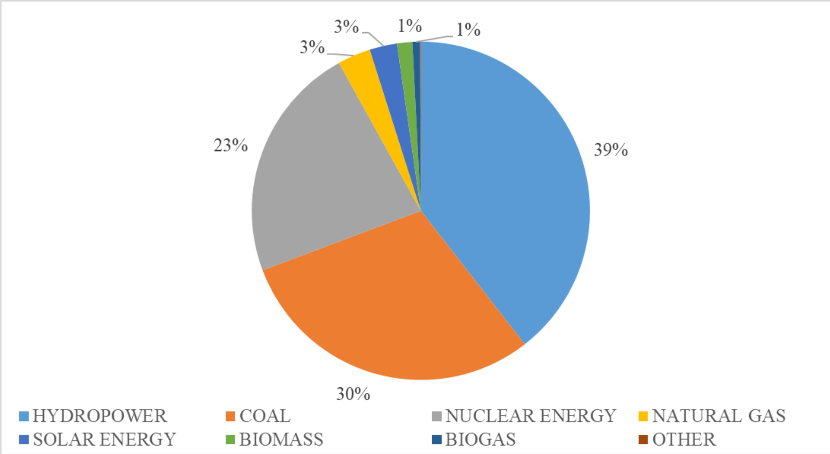
2 EXISTING ELECTRICITY GENERATION AND CONSUMPTION AND FUTURE PROSPECTS

2.1 Existing electricity generation and consumption

In 2019, the total final energy use in Slovenia was 57.7 TWh. Disaggregated by fuel, electricity amounted to 13.78 TWh or 24% of total final energy use, behind only oil products with 26.14 TWh or 45% (Statistični urad, n. d.). In 2020, total domestic production amounted to 12,727 GWh, of which generation connected to the transmission network reached 11,639 GWh and generation connected to the distribution system 1,088 GWh (Agencija za energijo, 2020, p. 25). As total electricity consumption was 13,744 GWh, the imports equalled 1,017 GWh. In 2020, the demand covered by domestic generation was thus 92.6%, making it the highest share in the last five years. In the 2016–2020 period, import dependence ranged between 7.4–17.1%.

The Figure 3 (Agencija za energijo, 2020, pp. 22, 251) shows domestic electricity generation in 2020 by energy source. The most significant share was covered by hydropower, followed by coal and nuclear. Other sources, namely natural gas, solar energy, biomass, biogas and other, contributed only 8%. Two thirds of the consumed domestic electricity was produced from low-carbon sources (i.e. all energy sources excluding natural gas and coal), while the remaining, carbon-intensive part came from coal (30%) and natural gas (3%).

Figure 3: Electricity generation by energy source in 2020 (%)



Source: own work based on Agencija za energijo (2020).

Coal and natural gas are fossil fuels and generate 820 and 490 tonnes of CO_2-eq. per GWh, respectively, over the lifecycle of a power plant (Ritchie, 2020). Decarbonisation efforts should therefore focus on both, but priority should be given to coal. Insights in terms of the extent, complexity and roles of different gas- and coal-fired power plants in Slovenia are crucial if I am to conceive sensible dates of fossil fuel phase-out and new roles potentially attached to such power plants. This topic will be addressed in the following subchapter.

2.2 Coal and natural gas in existing electricity generation[3]

Natural gas is used in open cycle gas turbines (OCGT) and various combined heat and power (CHP) plants. TEŠ owns two OCGT units with a generating capacity of 42 MW each that represent strategic reserves and provide peak load electricity when most needed. Additionally, they can provide mFRR and heat to the Šaleška valley if coal-fired units are under repair. In Thermal Power Plant Brestanica (TEB), seven gas turbines are located with a total generating capacity of 406 MW, of which 250 MW are used for mFRR, while the remaining part represents strategic reserves. TEB also provides black start or system restart. As for CHP plants, natural gas provides approximately 35% of all primary energy used in all CHP stations (Agencija za energijo, 2020, p. 251). An essential characteristic of CHP plants is that they produce electricity and heat during winter months when demand is at its highest and generation from solar power plants at its lowest.

Coal is used in coal-fired (thermal) power plants and CHP plants. TEŠ encompasses lignite-fired units 4, 5 and 6. Unit 4 has an operating permit until the end of 2022, but it is no longer in use because it has been superseded by modernized and more efficient units 5 and 6. Due to high carbon prices, soon only the more efficient unit 6 (TEŠ6) will be in operation (S-TV

[3] Power plants with negligible impact on the electric power system and GHG emissions (e.g. two units of HSE ED Trbovlje, Heating Station Šiška of Energetika Ljubljana) are left out of the text for clarity.

Skledar, 2021). Its generating capacity is 543 MW, and it represents the main load-following power plant in the Slovenian electric power system. By adjusting its output as electricity demand fluctuates throughout the day, it provides an essential service to the broader system and ensures the security of supply. Additionally, it delivers ancillary services, more precisely FCR and aFRR (±45 MW) (Žerdin et al., 2021, p. 196), to the system and heat to households and businesses in the Šaleška valley.

CHP plant Ljubljana (TETOL) co-generates heat and power in three units with hard coal and woody biomass. In 2019, 109 MW of installed capacities generated 265 GWh of electricity from hard coal, and 8.9 MW of installed capacities produced 44.7 GWh of electricity from woody biomass. In 2022, coal-fired units 1 and 2 will be replaced with two combined-cycle gas turbines (CCGT) of 57 MW each (Agencija Republike Slovenije za okolje (ARSO), 2020, p. 4). CCGTs will also capture waste heat and transport it to residents and industries in Ljubljana. The power plant could also be used for FCR, aFRR and black start. Natural gas will be utilised as the primary fuel and extra light heating oil as the secondary fuel.

2.3 Future direct and indirect electricity consumption

Judging by the ongoing electrification of transportation, heating, industrial and other sectors and thorough energy efficiency measures, electricity consumption is expected to increase and total final energy consumption to decrease. The NECP and Long-term Climate Strategy predict a 40% increase in electricity demand in 2050 compared to 2020 and an almost 30% drop in final energy consumption in the same period (Portal Energetika, 2019[4]). ELES has also predicted an increase in electricity demand, but final energy use does not drop in all of its scenarios (ELES, 2020, p. 67). Although the latter aspect bears immense importance from a societal point of view, it is not a crucial figure for my plan. A notable growth in electricity consumption (and a significant reduction of final energy demand) is also anticipated by the Climate Action Network Europe (CAN EU), a progressive consortium of nongovernmental climate organisations from all over Europe. They have modelled the Paris Agreement Compatible (PAC) energy scenario for Europe, where the EU reaches net-zero emissions by 2040 (PAC Scenario, 2020). This scenario assumes even higher electricity growth rates than Slovenian national climate documents. What do such predictions mean for my scenario?

To align with the aforementioned climate pillar and thus the Paris Agreement, Slovenia should reach net-zero carbon emissions a few years after 2040 and not by 2050 as national and European documents prescribe. Consequently, Slovenia should deepen and accelerate its decarbonisation efforts in all sectors, which would – as underlined in the progressive CAN Europe scenario – cause an even higher electricity demand than anticipated by national institutions. Consequently, figures for direct electricity consumption estimated by the NECP

4 Data taken from the ambitious scenario with additional measures (DUA), which was chosen as the most appropriate plan by the Ministry of the Environment and the Slovenian government. The nuclear DUA scenario (DUA JE) and synthetic natural gas DUA scenario (DUA SNP) are identical in terms of energy demand.

are shifted backward by five years, thus anticipating somewhat higher electricity demand than NECP.

Since direct electricity demand does not include losses in transmission and distribution networks, these values need to be added to obtain the total direct electricity consumption. Since 2010, losses have fallen by approximately 15% (Agencija za energijo, 2020, pp. 19–20). Future losses in the electric power system will be determined by the interplay between two opposing tendencies: continued investments in the reduction of the system's losses and a rapid expansion of local, national and international electricity grids. I therefore assume that losses will rise by a quarter of the predicted electricity demand growth rates. A similar development is anticipated by ELES (internal ELES document).

Total direct electricity demand is only one part of the story. Additional electricity will be needed to produce low or zero-carbon gases, namely hydrogen and synthetic natural gas. Such gases will be essential to decarbonise future natural gas consumption in the electric power system and hard-to-abate sectors. For example, the aforementioned CAN EU scenario envisions that about one third of the whole electricity consumption will be dedicated to the production of zero-carbon fossil gases and fuels (PAC Scenario, 2020). However, it is not necessary or economically sound to be self-sufficient in total direct and indirect electricity demand since conditions for production might be superior in foreign countries. My proposed plan aims to generate a sufficient amount of hydrogen and SNG in Slovenia to cover the demand for gaseous fuels in the electric power system and CHP part of the heating sector by around 2036. Hydrogen and SNG used in industry, transport and other sectors would be covered by imports. Projects and initiatives in areas as diverse as Africa and the North Sea are already underway (European Commission, 2020, p. 2; Africa–EU Energy Partnership, 2020; North Sea Energy, n. d.).

As shown in detail in subchapter 5.4.4, such an output would mean that more than half of the Slovenian demand for gaseous fuels would be covered by domestic sources by 2040 (Portal Energetika, 2019), and the remaining part would be imported. In addition, we also need to consider the electricity consumed by batteries, whereas consumption by pumped storage hydropower plants is presumably already included in the NECP's direct electricity consumption.

Tables 3 and 4 show the projected total direct (including losses) and indirect electricity demand that was calculated based on data presented in chapters 5.3 and 5.4. Projections from CAN EU[5] (PAC Scenario, 2020), the Consortium for the Promotion and Acceleration of Green Transformation of Slovenian Energy System with the Aim of Decarbonisation of Slovenia by 2050 (hereinafter Consortium) (conversation with a GEN-I employee; GEN-I, 2019)[6], led by GEN-I and ELES, and scenario prepared by Slovenian Academy of Sciences

5 As the scenario is modelled for the EU, its ratios are applied to the Slovenian case.

6 The second Consortium's scenario is somewhat different during the initial period, but it gradually coincides with the first one when approaching the year 2050.

and Arts (hereinafter SAZU) (SAZU, 2022) have been added for the sake of comparison. Total direct and indirect electricity consumption by 2040 is expected to amount to 28.2 TWh, or 19.4 TWh direct and 8.8 TWh indirect consumption. In relative terms, 69% would be used by direct consumers, 28% by electrolysers and 3% by batteries. My projected electricity consumption is higher than the one given by Consortium and in line with the one proposed by SAZU and by CAN EU. The latter represents the scenario envisioned by a progressive consortium of nongovernmental climate organisations from all over Europe according to which the EU would decarbonize by 2040.

Table 3: Total direct and indirect electricity consumption over the 2021–2040 period (GWh)

ELECTRICITY CONSUMPTION (GWh)	2021	2025	2030	2035	2040
DIRECT ELEC. CONSUM. (incl. losses)	14,253	15,723	17,557	19,303	19,442
ELEC. CONSUM. BY BATTERIES	30	199	497	796	845
ELEC. CONSUM. BY ELECTROLYSERS	0	26	329	4,396	7,945
TOTAL DIRECT AND INDIRECT ELECTRICITY CONSUMPTION	**14,282**	**15,949**	**18,383**	**24,494**	**28,233**

Source: own work based on Agencija za energijo (2020) and Portal Energetika (2019).

Table 4: Total electricity consumption – comparison of four models (TWh)

TOTAL ELECTRICITY CONSUMPTION (TWh)	2020	2025	2030	2035	2040
Consortium	13.50	15.00	17.70	20.70	24.90
CAN EU	14.53	16.94	22.65	28.06	28.10
SAZU	14.42	15.74	19.71	24.64	28.00
Ostan Ožbolt	14.28	15.95	18.38	24.49	28.23

Source: own work; conversation with GEN-I employee; PAC Scenario (2020) and SAZU (2022).

2.4 Future peak load and role of demand-side management

An electric power system is primarily not designed to cover an average load on a typical day but to secure adequate supply to match peak load. Therefore, it is essential to outline a future energy plan guaranteeing a stable, reliable and adequate system capable of meeting peak load. The latter occurs in the evening hours of winter months, mainly in January (ELES, 2020, p. 36). Future peak load for the 2021–2030 period has been constructed by taking (transmission-based) peak load for the same time span from ELES (2020, p. 72), adjusting it for hourly transmission network losses and adding hourly power output of power plants connected to the distribution network (Mervar, personal communication). As the increase in electricity consumption in my data is highly similar to the one projected by ELES, the peak load by 2030 has not been further adjusted. The peak load for 2030–2040 has been calculated by multiplying the peak load with the yearly consumption growth rate (Mervar, personal communication). Such an approach is sensible as a significant correlation between consumption growth and peak load growth exists (ELES, 2020, p. 71). The results are shown in Table 5.

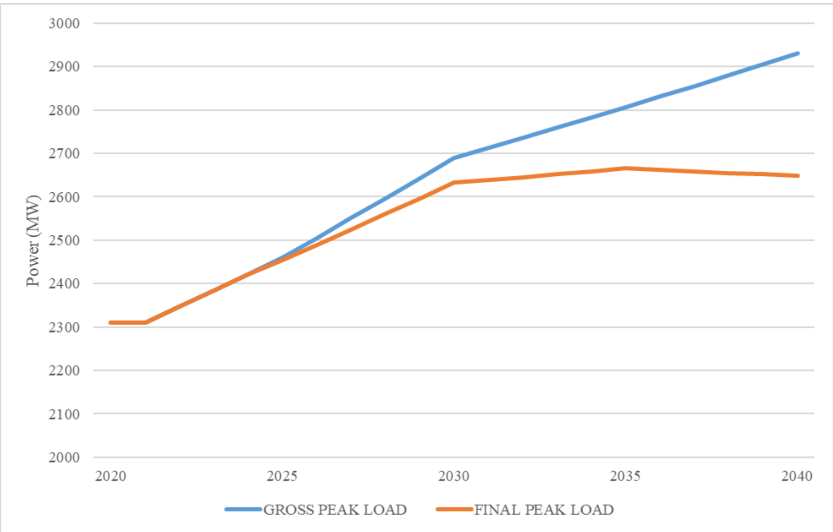
Peak load can be reasonably reduced with demand-side management (DSM), which "refers to initiatives and technologies that encourage consumers to optimise their energy use" and "shift their energy consumption from peak to non-peak hours" (EMA, n. d.). It will be thoroughly explained and projected in subchapter 5.2. DSM capacity assumptions are taken from Consortium (conversation with an ELES employee) and based on various studies augmented by 50% (Sistemski operater distribucijskega omrežja, 2020, p. 93; ELES, 2020, p. 81; Elektro Maribor, 2019; iEnergija, n. d.; Smart Energy Europe, 2021, pp. 5–6; Lagler et al., 2014). Similarly, Consortium's availability factor of 0.15 has been raised to 0.1875 (i.e. a 25% increase). Table 5 shows gross peak load, DSM capacities and DSM-adjusted final peak load. Figure 4 plots the results visually.

Table 5: Gross peak load, DSM capacities and DSM-adjusted final peak load over the 2021–2040 period (MW)

PEAK LOAD (MW)	2021	2025	2030	2035	2040
GROSS PEAK LOAD	2,310	2,459	2,689	2,807	2,930
DEMAND SIDE MANAGEMENT		6	56	141	281
FINAL PEAK LOAD	**2,310**	**2,453**	**2,633**	**2,666**	**2,649**

Source: own work based on conversation with ELES employee; Sistemski operater distribucijskega omrežja (2020); ELES (2020); Elektro Maribor (2019); iEnergija (n. d.); Smart Energy Europe (2021) and Lagler et al. (2014).

Figure 4: Gross and final peak load 2020–2040 (MW)



Source: own work based on conversation with ELES employee; Sistemski operater distribucijskega omrežja (2020); ELES (2020); Elektro Maribor (2019); iEnergija (n. d.); Smart Energy Europe (2021) and Lagler et al. (2014).

Since sensible decisions on future power plants hinge on a clear projection of future coal-based electricity supply, the following section aims to determine a coal phase-out plan in Slovenia.

3 FOSSIL FUEL PHASE-OUT IN SLOVENIA

3.1 Fossil fuel phase-out in the context of expected reforms of EU Emission Trading System

The European Union reduces GHG emissions from the energy and industry sectors through the European Union Emission Trading System (EU ETS), under which utilities and enterprises must buy one European Emission Allowance (EEA) for each tonne of CO_2 emitted. Each year, the total amount of CO_2 emissions that businesses can emit diminishes linearly in line with the long-term climate goal, translating to a lower supply of EEAs and a higher price of each allowance. As of May 14, 2021, the linear reduction factor (LRF) was 2.2% per year until 2030 (Pietzcker, Osorio & Rodrigues, 2021, p. 4). The aim was to reduce GHG emissions by 43% compared to 2005 in the sectors covered by EU ETS, and by 40% compared to 1990 on the EU level. In September 2020, the EC proposed a more ambitious climate target – to reduce GHG emissions on the EU level by 55% instead of 40% compared to 1990 (European Commission, 2020, p. 2). EU leaders upheld the objective in December 2020 (McGrath, 2020a). In April 2021, the European Parliament and the European Council reached a provisional agreement on European Climate Law (European Council, 2021), underlying the goal of cutting carbon emissions by at least 55% by 2030. Such reduction presents an essential step towards reaching climate neutrality by 2050. In the summer months of 2021, the EC is to present its measures and policies to achieve the goal, and update the targets and the linear reduction factor in the EU ETS framework. As of May 14, 2021, the EC has not specified the new EU ETS target yet. Its impact assessment from 2020 proposes different scenarios where the reduction of emissions within EU ETS by 2030 ranges from 64% to 65% (European Commission, 2020b, p. 98). This goal is to be achieved by increasing LRF to 6.79% from 2026 onwards (Pietzcker, Osorio & Rodrigues, 2021, p. 4). Applying the same LRF also throughout the next decade, such a steep reduction rate would mean that the last certificates would be issued in 2035 (i.e. de facto net-zero emissions in electric power systems on the EU level by 2035) (Pietzcker, Osorio & Rodrigues, 2021, p. 4). Alternatively, by extrapolating the previous proportion between the ETS reduction target and the non-ETS reduction burden and employing the amended LRF already in 2021, Pietzcker, Osorio and Rodrigues (2021, p. 4) estimated that the new reduction objective for EU ETS would amount to 63% by 2030 with LRF of 4.26%. The final EEAs would thus be auctioned no later than 2040 (i.e. net-zero carbon emissions in electric power systems by 2040). Both possible paths are roughly in line with the announcement made by a Slovenian senior official that the t2030 arget is going to range from 66% to 69% (Mestna občina Velenje, 2021). All three potential scenarios describe a remarkable departure from the previous 43% target and an immense acceleration in fossil fuel phase-out.

Pietzcker, Osorio and Rodrigues (2021) from the renowned Potsdam Institute for Climate Impact Research ran a complex power sector model LIMES-EU and provided a seminal insight into the future use of fossil fuels in electric power systems across the EU. With the new, tightened climate targets and consequently higher EUA prices[7], the fossil fuel phase-out and the expansion of low-carbon alternatives unfold 10–15 years faster than indicated by previous targets (Pietzcker, Osorio & Rodrigues, 2021, p. 7 and 8). The effective termination of coal usage[8] is to be achieved by the end of this decade and not around 2045 as previously anticipated, and after 2030, coal-fired power plants are to be almost exclusively utilised only as a backup reserve. These findings resonate with a study conducted by Climate Analytics (2019, p. 4), which found that OECD countries should phase out coal by 2031 to meet the Paris Agreement objectives. Since natural gas has a lower carbon intensity than coal, phase out would occur more gradually, but still faster than formerly predicted. The results show a surge in new OCGTs until 2025, after which high CO_2 prices are to push natural gas-fired power plants, which are to be gradually replaced by hydrogen plants, into a steady decline. In this scenario, natural gas would be confined to covering peak load and periods with low generation from RES, and its use in electric power systems would end by 2045 on the EU level. Despite the rapid rise in carbon prices and more stringent climate targets, fossil fuel-based power plants with carbon capture and storage would not take off significantly. Some carbon capture and storage projects would be constructed, but their share would remain negligible due to high costs and slow development. Accounting for negative emissions, the model predicts an EU-wide electric power system with net-zero carbon emissions by 2040. Without carbon sinks, the entire decarbonisation period would last a few years longer. Therefore, recent changes in EU climate and energy legislation point to a much more rapid fossil fuel phase-out in the energy sector than assumed only one or two years ago. Additionally, it should be noted that the trends described above are first and foremost driven by the economics of electricity generation and operation of various types of power plants.

3.2 Phase-out of coal-based generation in Thermal Power Plant Šoštanj

3.2.1 Future projected losses, date of coal phase-out and the newly established energy company Green Shine

The question of phase-out is highly complex and contentious when it comes to the lignite-based units in TEŠ. Unit 5 and especially unit 6 provide around 27% of Slovenian electricity in a load-following manner irrespective of weather conditions. They also supply heat to the

7 100 EUR/tCO2 in 2025, 129 EUR/CO_2 in 2030, 210 EUR/tCO2 in 2040 and 350 EUR/tCO_2 in 2050.

8 Authors define a phase-out of a specific energy source as a state where the energy source in question provides less than 1% of the total electricity supply.

Šaleška valley and ancillary services to the whole energy system. In 2019, TEŠ employed 319 workers. In 2020, Coal Mine Velenje Group directly employed 2047 workers, of which 1,145 were coal miners (Žerdin et al., 2021, p. 52). The remaining 902 were employed in the other three companies within PV Group, which do not depend solely on coal mining activities. Together, TEŠ and PV Group employ above a tenth of the total working population in the region, and additional tenth of the local industry, i.e. approximately 1,500–2,000 workers, directly relies on the revenues from mining (Deloitte, 2021, p. 8). Thus, around 3,500 workers are indirectly and directly attached to the mining and electricity sector in the region. Additionally, TEŠ, PV and other coal-related enterprises generate about a third of overall revenues in the local community (Deloitte, 2021, p. 8). Lastly, Slovenian electricity prices for industry and households are below the EU average (Electricity price statistics, 2021), but this could change if the transition is not managed sensibly. The situation has become even more convoluted due to the unprecedented rise in EEA prices since the end of 2020. Carbon prices rose from 19.2 to 56.65 EUR/t in only one year (May 14, 2020–May 14, 2021) (ICE data taken from Ember, 2021) and they will most likely continue to rise. In 2021, based on the aforementioned more ambitious targets set by the EU, experts from BloombergNEF, Energy Aspects and Refinitiv separately claimed that high carbon prices do not present a temporary market aberration and predicted steadily rising prices throughout the decade (Marcu et al., 2021, p. 28). These findings resonate with the study by Pietzcker, Osorio and Rodrigues (2021) cited above. The predictions were that the price of EEA will hit 75 EUR/t (Energy Aspects), 90 EUR/t (Refinitiv), 109 EUR/t (BNEF) or even 129 EUR/t (Pietzcker, Osorio & Rodrigues) by 2030.

Entirely new circumstances also made pre-2021 coal studies relatively obsolete. To mention just a few most eye-catching examples: the EEA prices used in the Amended Investment Plan – Revision 6, on which the entire investment in unit 6 was based upon, were 8.1 EUR/t in 2021 and 27.10 EUR/t in 2030 (Termoelektrarna Šoštanj, 2014, p. 93). The NECP took assumptions about future EEA prices from the EC, which in 2018 estimated that carbon prices will reach approximately 20 EUR/t in 2021 and roughly 35 EUR/t in 2030 (Vlada Republike Slovenije, 2020, p. 125). As has already been mentioned, as of May 17, 2021, the EEA price is 55.3 EUR/t and is expected to rise to somewhere between 75–129 EUR/t by 2030. What such a striking difference between predictions and reality means for the business performance of TEŠ is probably best illustrated in a recent study prepared by Deloitte for the Ministry of Infrastructure. The carbon prices used in the National Strategy for Phasing Out Coal and the Restructuring of Coal Regions in Line with Just Transition Principles, written in 2020 and submitted to public consultation between March 15 and April 15, 2021, were taken from the NECP. Deloitte assessed that earnings before interest, taxes, depreciation and amortization (EBITDA) would not become negative earlier than 2043 (Deloitte, 2021, p. 13). In reality, EBITDA has been already negative since April 2021 (Mestna občina Velenje, 2021), which makes past studies relatively obsolete. Moreover, since up-to-date studies are at best rare or are yet to be conducted, it is even harder to make sound decisions. A thorough national study on TEŠ and PV, which will consider described new reality, will be prepared and included in an amended version of the NECP no earlier than 2023 or 2024. Be that as it may, Slovenian energy experts and senior officials provided some valuable and thorough insights that provided the foundation for the ideas presented in the following chapters.

The economic performance of TEŠ has been questionable ever since unit 6 began to operate in 2016. Up to May 2021, the HSE Group has helped TEŠ with EUR 823M (S-TV Skledar, 2021). Moreover, in 2019, the TEŠ's EBIDTA was EUR 44.6M (EUR 22.2M in 2018) and EBIT EUR 6.5M (EUR –33M in 2018) (Termoelektrarna Šoštanj, 2020, p. 12). When the financial expenses of EUR 26M in 2019 (EUR 25.5M in 2018) (Termoelektrarna Šoštanj, 2020, p. 80) are taken into account, net loss was EUR 19.6M in 2019 (EUR 58.5M in 2018) (Termoelektrarna Šoštanj, 2020, p. 18). However, the recent spike in carbon prices has made the already murky situation even worse. The CO_2 prices will continue to rise; the exceptionally high electricity prices during the winter of 2021/2022 are of a different nature. As can be observed on the energy futures market, electricity prices will gradually recede, and harsh reality for coal-fired power plants will return. To the best of my knowledge, no studies have yet been done on how such a situation will impact TEŠ, but skyrocketing electricity prices should and will be considered when determining the timeline of state aid and Slovenian coal phase-out in the following part.

On May 7, 2021, dr. Vračar, general director of the HSE Group, said that if the above-mentioned trends continued as predicted, TEŠ would experience a loss of EUR 110–150M per year (S-TV Skledar, 2021). According to him, the HSE Group could cope with TEŠ and PV losses until the end of 2022 by using the EUR 138.7M from a settlement with General Electric, postponing some of the investments, building upon hedged EEAs with a lower price and reducing electricity production, thereby lowering total costs for EEAs. In a more optimistic scenario, electricity prices would rise and move more in line with carbon prices, in which case HSE could bear the burden throughout 2023 and then require external (state) aid. Vračar's position resonates with insights provided by mag. Šolinc, general director of the Energy Directorate at the Ministry of Infrastructure (Hozjan, 2021). He stated that based on high carbon prices, an optimistic scenario would be to phase out coal in TEŠ by 2029, but he was also worried that it would be terminated as fast as 2024. What is more, he considered the debates and disputes about the most appropriate phase-out date (2033, 2038 or 2042) to be irrelevant, as coal is likely to be out of the energy mix much before 2033. A similar position was put forward by mag. Mervar (Volfrand, 2021, p. 39), who said that the HSE Group could manage TEŠ's losses for another year or two, no more. Without the help of the Slovenian Sovereign Holding (SDH) and other actors, coal phase-out would happen "much, much faster" than in 2033 (Volfrand, 2021, p. 39). Lastly, such outcomes have also been underlined in the study on future TEŠ losses from 2021 to 2030 prepared by the analytics company Ember for the Slovenian non-governmental organisation Focus (Ember, 2021). Even though the economic outcomes for coal-fired thermal power plants have improved due to the extremely high electricity prices during the winter of 2021/2022, electricity futures markets show that prices are gradually going to decrease, making TEŠ unprofitable again. To proceed with my calculations, Vračar's optimistic scenario, stated on May, 2021, is taken and increased by two years due to high electricity prices during the winter of 2021/2022 and the near future. The extension stems from informal talks with experts close to TEŠ. Thus, I assume that if TEŠ did not receive state aid (more on this later), TEŠ would be shut down in 2026.

Table 6 shows TEŠ's profit and loss statement for the 2026–2028 period. Due to high carbon prices, only the more efficient unit 6 is taken into account, whereas unit 5 is envisioned to terminate its operation in a few years (S-TV Skledar, 2021). As higher carbon costs will make the TEŠ costlier to operate, its generation is projected to reduce – 2,600 GWh in 2026 and 2,100 GWh in 2027. Assumed future production is higher than the projections made by GEN-I in their scenario of a planned and gradual phase-out of coal by 2030 (conversation with a GEN-I employee). The reason is primarily economic since lower generation means higher cost prices due to increasing fixed and variable costs per MWh (Žerdin et al., 2021, p. 109). Future increase in the carbon costs by 2030 has been calculated based on the average taken from four different studies presented above (Marcu et al., 2021, p. 28; Pietzcker, Osorio & Rodrigues, 2021, p. 9). TEŠ's electricity cost prices are taken as a baseline from the study performed at ELES (Žerdin et al., 2021, pp. 106–109), where TEŠ's cost prices are calculated at different carbon costs, quantities of electricity generation and coal costs. The last two are interconnected – lower generation means an increase in coal costs (EUR/GJ), as the same PV's fixed costs are distributed over a smaller amount of electricity generated. ELES's estimations of coal costs at different electricity production levels mean that the PV would not bear any losses. For the baseline of my calculations, I took TEŠ's cost prices at the carbon cost of 42.8 EUR/t, electricity generation of 2,600 GWh and 2,100 GWh, and coal costs high enough for the PV not to bear any losses. To adjust for higher carbon costs, the average increase in TEŠ's cost price when carbon cost rises by 1 EUR/t was calculated based on ELES's data (Žerdin et al., 2021, pp. 106–109). Equation (1) provides a methodology to obtain TEŠ's cost price suitable for my master's thesis.

$$P_{TEŠ,t} = P_{TEŠ-ELES,p,c} + (x - 42.8) * 0.8525 \qquad (1)$$

$P_{TEŠ,t}$= Cost price of TEŠ in year t (EUR/MWh)

$P_{TEŠ\text{-}ELES,p,c}$ = cost price of TEŠ calculated by ELES at the carbon cost of 42.8 EUR/t and different amounts of electricity generation and coal cost in year t (EUR/MWh)

x = cost of EU Allowance (EUR/tCO_2)

0.8525 = average increase in TEŠ's cost price when carbon cost rises by 1 EUR/t (EUR)

In the absence of the Slovenian EEX power forward curve and as prices for Hungarian futures after 2024 are not available[9], futures prices (as of December 1–15, 2021) for 2026 and 2027 from EEX Austrian power futures curve are used (EEX, n. d.; see also Ember, 2021). 0.7 weight is utilised for baseload electricity and 0.3 for peak-load electricity (Mervar, 2019a, p. 9). Additionally, the electricity prices are increased by the amount of the average calendar year spread of Hungarian prices over Austrian prices, i.e. 1 EUR/MWh (Ember, 2021, p. 5). The prices for 2028 are calculated based on the reduction rate for the preceding years.

Table 6: Profit and loss statement of Thermal power plant Šoštanj over the 2026–2028 period

TEŠ	2026	2027	2028
TEŠ generation (GWh)	2,600	2,100	2,100
Cost of carbon (EUR/t)	80	85	90
Cost of coal (EUR/GJ)	4.40	5.25	5.25
Cost price (EUR/MWh)	151	171	175
Total costs and expenses (EUR M)	393	359	368
Electricity price (EUR/MWh)	91	88	85
Total revenue (EUR M)	236	185	179
Profit and loss statement (EUR M)	-158	-174	-189

Source: own work based on Žerdin et al. (2021); Marcu et al. (2021); Pietzcker, Osorio & Rodrigues (2021) and EEX.

As can be seen in the Table 6, the cost prices are expected to rise from 151 EUR/MWh in 2026 to 175 EUR/MWh in 2028, and losses would increase from EUR 158M to EUR 189M per year. Although TEŠ burns coal and generates a loss, it is sensible to consider different possibilities of state aids due to the following four arguments. First, TEŠ provides essential services in terms of the reliability and security of the electric power system, which cannot be immediately replaced. Second, TEŠ and PV are two of the biggest employers in the broader SAŠA region and provide essential benefits to the Slovenian economy. Third, my calculations show that with a cost price of 150–170 EUR/MWh, TEŠ would still supply price-comparable electricity to various alternatives. Lastly, excessive hourly and yearly import dependence caused by a premature closure of TEŠ would threaten the reliability and security of the electric power system. However, these conditions can be ameliorated through sensible policies in the following years, and state aid should be limited in size and time span only to enable the necessary investments in services once supplied by TEŠ, keep Slovenia from exposing itself to excessive import dependency, provide more time for local communities to proactively counter the adverse effects of coal phase-out and not subsidise energy source with a substantially higher cost price. As will be thoroughly explained in the subchapters 4.1 on solar power, 4.2 on wind power, 4.4 on CHP plants, 4.6 on CCGTs and

9 Historically the prices for these two countries have closely tracked each other.

4.7.3 on OCGTs, by the end of 2027, Slovenia could set up a sufficient number of power plants, especially CHP plants, solar power plants, OCGTs and CCGTs, to cope with the most adverse effects of coal phase-out. Combined with the progress described in the subchapters 5.2 on DSM, 5.3 on batteries, 5.6 on covering the peak load, 5.7 on aFRR and 6.1 on electricity balance, the proposed development would adequately replace electricity from unit 6, guarantee reliability of supply, assure security of supply on an hourly and yearly basis and push import dependence significantly below 25% (see subchapters 5.6 and 6.1.1), which is the value the NECP deems acceptable (Žerdin et al., 2021, p. 195). The proposed shift would also make economic sense. Building upon the methodology, equations (6-9) and data from subchapter 6.3.1 on cost prices, in 2028, TEŠ would run at a higher cost price than its six potential substitutes – OCGTs, solar power plants (SPP), wind power plants (WPP), CHP plants (gas turbines and GCGTs, both capturing waste heat), CCGTs and imports. The results are shown in Table 7. Importantly, OCGT, CCGT and CHP station are the three types of power plants most suitable for generating electricity when it is needed the most, namely during the colder months in the morning and evening. As has already been indicated and will be more thoroughly examined later on, state aid spanning from the onset of 2026 until the end of 2027 is justified. Coal would thus no longer be used in TEŠ by the end of 2027. Furthermore, prolonging aid beyond 2027 is highly questionable from a legal perspective as well. A minimum span of state aid is an essential condition set by the EC: "The amount and intensity of restructuring aid must be limited to the strict minimum necessary to enable restructuring to be undertaken." (European Commission, 2014, p. 12). Since such aid is "among the most distortive types of State aid" (European Commission, 2014, p. 3), the conditions for approval are strict. For example, in its preliminary assessment of the request submitted by Romania for issuing state aid to restructure the mostly state-owned, coal-based energy firm Complexul Energetic Oltenia SA, the EC stated that it had "doubts at [that] stage about the compatibility of the restructuring plan with the principal requirements of the R&R Guidelines" (European Commission, 2021a, p. 23). This means that even the state aid proposed for the 2026–2027 period cannot be taken for granted, let alone for 2028 or subsequent years.

Table 7: Cost prices of various power plants in 2028 (EUR/MWh)

COST PRICES IN 2028 (EUR/MWh)	
TEŠ	175
CHP NATURAL GAS	101
OCGT NATURAL GAS	148
CCGT NATURAL GAS	111
SPP ON TN	41
SPP ON DN	65
WPP	59
IMPORTS	85

Source: own work based on Fürstenwerth (2014); Pietzcker, Osorio & Rodrigues (2021); Mervar (2014 and 2019a); Žerdin et al. (2021); EEX; EC (2016b and 2020e); ENCO (2020); Egli, Steffen and Schmidt (2019); Polzin et al. (2021) and Bachner, Mayer & Steining (2019).

EU provides different forms of state aid to energy companies. For coal-generation units in TEŠ, officials from HSE Group recognize four potential forms of support (Mestna občina Velenje, 2021): Capacity Remuneration Mechanisms (CRM), free allocation of EEAs, resources allocated from the Modernisation Fund and other options (e.g. subsidies for coal phase-out, covering the costs of EEAs). First, for Slovenia, free allocation of EEAs to power plants is no longer an option (European Commission, n. d. a). Second, the Modernisation Fund provides different forms of support for reaching climate neutrality to the ten lowest-income EU member states. As Slovenia is not among them, the resources from the Modernisation Fund cannot be used for TEŠ (European Commission, n. d. b). Third, to ensure the electricity demand is always met, power plants can receive funds through CRM if they are on standby to generate electricity when needed; the emission thresholds are, however, very strict and TEŠ will be eligible for CRM only until June 1, 2025 (Agency For The Cooperation Of Energy Regulators, 2019, p. 3), thus prior to the required state aid from 2026 onwards.[10] The last alternative mentioned by dr. Vračar are “other support options” (e.g. subsidies for coal phase-out, covering the costs of EEAs). Such actions are not allowed under the Guidelines on State aid for environmental protection and energy 2014–2020 (as of May 2021, the updated guidelines are not yet available, but if anything, conditions will be even more strict (Lewitt, Hancher & Gabathuler, 2020)) nor is coal-related aid possible under the Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post-2021. Nevertheless, the Guidelines on State aid for rescuing and restructuring non-financial undertakings in difficulty do provide some space for TEŠ

10 Approval conditions for obtaining CRM are very stringent. Since the Slovenian electric power system is well integrated into the EU-wide system, it is far from certain that the European Commission would approve the potential request made by Slovenia. Even if the request was approved, as CRM is deployed by auction, it is uncertain whether exactly TEŠ would receive it (Mestna občina Velenje, 2021). Finally, CRM is not a silver bullet for TEŠ even from a financial perspective. The currently proposed value is unknown, but in 2016–2017, when the last (failed) CRM implementation attempt occurred in Slovenia, the maximum amount allowed by the European Commission was capped at only EUR 25M per year (Hočevar, 2017a; Hočevar, 2017b).

(European Commission, 2014). A request from Romania to the EC to allocate state aid to the primarily state-owned coal-based energy company Complexul Energetic Oltenia SA, which generates 23% of Romanian electricity, can be used as a helpful reference and orientation (European Commission, 2021a). The exact legal status of TEŠ and PV during and after the restructuring period and their role within the HSE Group are yet to be fully determined. Nevertheless, broadly speaking, there are two options (Mervar, 2021).

The first option is a merger of the HSE Group and the GEN Group. The former holds significant loss-making fossil fuel assets, whereas the latter generates significant profits due to an amortized low-carbon fleet. If the two entities join, they could cover and cope with the rising losses incurred by TEŠ and PV. As Mervar has remarked (2021), the merger could hamper the potential funding of the JEK2. What is more, as the portfolio of such a merged company would include a coal mine and coal-fired power plant, the conditions and requirements of debt financing would mostly likely deteriorate, especially considering the environmental, social and governance (ESG) criteria. Furthermore, such intentions would undoubtedly face opposition from a strong energy lobby around the GEN Group and its beneficiaries, which would prolong and delay a potential solution for the Šaleška valley and increase the uncertainty of the situation. It is thus unlikely that such an option could be realized anytime soon, which makes it incompatible with the immediate urgency of a restructuring plan for the Šaleška valley.

The second option, which I believe to be more realistic and have therefore proposed it in the master's thesis, is that TEŠ and PV are separated from HSE Group and an independent company is established. The losses would be covered by the state budget, whereas the profit-making parts of the HSE Group, namely Dravske elektrarne Maribor (DEM), Soške elektrarne Nova Gorica (SENG) and Hidroelektrarne na spodnji Savi (HESS), would merge with the GEN Group, providing it with additional resources for financing the construction of JEK2 and other green investments. The new enterprise, established through the merger of TEŠ and PV and disassociation from the HSE Group, will for the purposes of this master's thesis be named Green Shine.

3.2.2 Restructuring plan in line with EC's Guidelines on State aid for rescuing and restructuring non-financial undertakings in difficulty

3.2.2.1 Three arguments why the plan meets the eligibility conditions

To obtain state support in line with the EC's Guidelines on State aid for rescuing and restructuring non-financial undertakings in difficulty, funds should not only prevent negative consequences but should also restore "the long-term viability of the undertaking" (European Commission, 2014). Thus, this subchapter is divided into two sections. First, I will lay out three core premises for the aid that stem from the eligibility conditions defined in the guidelines and then present a restructuring plan. It is assumed that the reasoning below presents justifiable arguments for the EC to approve state aid to TEŠ and PV. In this scenario, coal-related objects in the Šaleška valley would be closed by the end of 2027 and not by the end of 2025.

The three arguments why support should be approved are as follows. First, state aid would contribute to the "prevention of social hardship" (European Commission, 2014). Second, state resources would control, manage and proactively tackle "a risk of disruption to an important service, which is hard to replicate and where it would be difficult for any competitor simply to step in" (Article 3.1.1. (b)). Third, state aid would make it less likely that "the exit of an undertaking with an important systemic role in a particular region … would have potential negative consequences" (Article 3.1.1. (c)).

Concerning the first premise, unemployment is a bit higher in the SAŠA region compared to the national average. As has already been pointed out, in 2019, TEŠ employed 319 workers, and in 2020, PV Group employed 2,047 workers, of which 1,145 were coal miners (Žerdin et al., 2021, p. 52). The remaining 902 were employed in other three companies within PV Group, which are partly dependent on the coal mining activities. Together, TEŠ and PV Group provide around 13% of total employments in the region (Žerdin et al., 2021, p. 23). Furthermore, tenth of the local industries directly rely on the revenues from mining and electricity generation sectors, which means additional 1,500–2,000 workers (Deloitte, 2021, p. 8). Therefore, approximately 3,500 workers, or roughly one fifth of regional employments, are indirectly or directly attached to coal- and electricity generation-related activities. TEŠ, PV and other coal-related enterprises generate about a third of overall revenues in the local community (Deloitte, 2021, p. 8). Therefore, a premature and unmanaged shutdown of two of the three largest regional employers would lead to long-lasting and detrimental social consequences for the whole region. Additional two years would provide some extra time for the socio-economic restructuring of the SAŠA region.

TEŠ does not only provide jobs, but also heat for the industry, households and other users in the valley. As the coal-fired unit 4 and heating unit 1 were shut down, units 2 (HU2) and 3 (HU3) provide all the energy. HU3 is powered by unit 6 and potentially unit 5 of TEŠ, whereas HU2 uses the heat from both gas-fired units and unit 5 of TEŠ (Komunalno podjetje Velenje, 2016). The biggest heat supplier is coal-fired unit 6 and when it undergoes maintenance, heat is generated by unit 5 and gas-fired units instead (Slovenska tiskovna agencija, 2021). Each gas-fired turbine can provide roughly 50 MW of heat, which means they can cover maximum regional demand, as peak heat demand is 100–105 MW (conversation with a Municipal services Velenje employee). However, although gas-fired units can cover peak demand, they were not designed for the task. Moreover, the existing system has a backup, whereas the one without coal-related objects would have none. One single technical problem, especially during the winter, could cause profound hardship throughout the region. Additionally, in economic terms, heat supply from OCGTs would most likely be costlier than coal-fired unit 6. In 2026, the electricity cost price of the gas turbine at TEŠ would surpass 160 EUR/MWh, adjusted for the carbon cost of 78.85 EUR/t (Cirman, 2013). On the other hand, the cost price of unit 6 would amount to 151

EUR/MWh[11]. State aid would thus grant the regional authorities two additional years for setting up an alternative heating system. As will be discussed in the restructuring plan below, this is a sufficient amount of time to fulfil the objective, built a gas-fired CHP plant and utility scale heat pumps, and help prevent "social hardship" (European Commission, 2014).

Negative consequences would also be felt on the national level. Since import dependency would increase and adequate strategic reserves and other power plants cannot be set up until 2026, Slovenia would excessively rely on foreign electricity. In times of crisis and without adequate strategic reserves, such a situation could lead to reductions and disconnections (Mervar, 2021). As shown in the subchapters on various power plants, namely CCGT (4.6), OCGT (4.7.3), CHP stations (4.6), solar energy (4.1) and wind energy (4.2), adequate capacities could be built by the end of 2027 (see subchapters 5.6 and 6.1.1 for the outcomes). On the national level, electricity prices present a significant determinant for the financial performance of industries and households. The cost price of unit 6 would amount to 151 EUR/MWh and 170 EUR/MWh in 2026 and 2027, respectively, which according to my calculations would still make it more or less cost-comparable to other alternatives. However, as Table 7 shows, by 2028 cost prices of substitutional energy sources and plants will already reach cost competitiveness. State aid would therefore prevent severe social and broader economic ramifications.

The second premise builds upon the implications of coal phase-out for the electricity supply on the national level and heating supply on the regional level since such a transition represents a "disruption to an important service, which is hard to replicate and where it would be difficult for any competitor simply to step in" (European Commission, 2014).

The question of electricity supply is, in fact, a question of its security and reliability. Regarding security of supply, "if we take into account how the system functions, the total deficit generated by the shutdown of TEŠ could be replaced by energy imports, as import capacities are sufficiently high (on average 3 GW). These assertions consider the normal conditions … Extraordinary circumstances … could lead to reductions in imports and cause certain risks. In such cases, we could certainly expect short-term price spikes." (Žerdin et al., 2021, p. 196) What is more, such a situation could lead to reductions and disconnections (Mervar, 2021). As has been described throughout the master's thesis, such outcomes could be prevented by a proactive construction of various new power plants until the end of 2027 (concretely, import dependence would vary between 15 and 17% from 2028 to 2032 and then fall significantly due to JEK2 (see subchapter 6.1.1); additionally, there would be more than enough power plants to cover the peak load safely (see subchapter 5.6)). Regarding reliability of supply, without TEŠ's unit 6, which provides essential ancillary services, the Slovenian electric power system would experience a "shortage of appropriate regulation volumes of aFRR and voltage control, whereas market liquidity of FCR and mFRR would

11 Municipality of Velenje and Šoštanj have had a deal with TEŠ on the heat supply for less than 50 EUR/MWh irrespective of the source (i.e. gas or coal). As the economic situation of TEŠ and PV deteriorates further, the deal could well be reformed and the price raised or deregulated.

be reduced" (ELES, 2020, p. 94; Žerdin et al., 2021, p. 197). The calculations presented in the subchapters on aFRR and mFRR (see subchapters 5.7 and 5.8) show that by 2028 the Slovenian electric power system (excluding TEŠ) could have sufficient capacities to assure a reliable supply.

On the regional level, as has already been mentioned, the absence of coal-fired units 5 and 6 would pose a significant threat to the reliability of the heating supply. By the end of 2027, gas-fired CHP stations and utility-scale heat pumps (more on this topic in the following part) could be set up to substitute the coal-based heating system and provide an "important service, which is hard to replicate" (European Commission, 2014).

The third and last premise is that prolonging and postponing the coal phase-out in the Šaleška valley would at least partly avert the possibility that "the exit of an undertaking with an important systemic role in a particular region … would have potential negative consequences" (Article 3.1.1. (c)). Here, the above-mentioned social, economic and technical, regional and national arguments intertwine and construct an additional pillar for EC to recognize and therefore approve state aid measures.

After the EC decides whether state aid is justifiable, it demands a coherent and well-founded restructuring plan, the objective of which is to "restore the beneficiary's long-term viability" through, for example, reorganization and rationalization, withdrawal from loss-making activities and diversification towards new and viable sectors. "Long-term viability is achieved when an undertaking is able to provide an appropriate projected return on capital after having covered all its costs including depreciation and financial charges". As a result, a restructured company should "compete in the marketplace on its own merits" (Article 3.1.2.). It is beyond the scope of the master's thesis to specify a highly comprehensive plan of the projects with a predicted return on capital that would render Green Shine profitable. Nevertheless, in the following section I have delineated future projects, total investment costs and EU, state and own funds required to cover the transition. I assume that the proposed projects and activities are, broadly speaking, appropriate to restore the viability of TEŠ and PV.

3.2.2.2 Detailed projects under the restructuring plan

Floating and ground-mounted solar parks

Subsiding areas above mining sites are vast and perfectly suitable for large, utility-scale solar parks. Calculations by PV identified at least 71.55 hectares (ha) of land suitable for such purposes (Žerdin et al., 2021, p. 70). Solar power plants would be located on the nearby lakes and the surrounding areas. As the study by Žerdin and co-authors did not identify the full potential (conversation with PV employees) and as there are no high opportunity costs regarding such installations on subsiding areas, I assume 60 ha or 84% of the identified land would be dedicated to solar parks. Assuming that 1.9 ha of land are needed for a solar power plant with a capacity of 1 MW and 19% solar panel efficiency (Huerta, 2021; Narasimhan, 2015), and that the efficiency would increase to 21%, 22.5% and 24% by 2030, 2040 and 2050, respectively (Kovač, Urbančič & Staničić, 2018, p. 23), installed capacity of SPPs would amount to 34 MW. Based on the investment costs of utility-scale solar parks taken from IEA's sustainable development scenario for Europe (2020, p. 419) and equation (2), total costs would amount to EUR 21.5M (2020 prices; all the investment costs hereinafter are at 2020 prices). More on the investment costs and the future of solar energy in Slovenia can be found in subchapter 4.1.

$$TIC_{t,tech} = investment\ cost_{t,tech} * MW_{tech} \tag{2}$$

$TIC_{t,tech}$ = total investment costs for a power plant in year t (EUR)

$Investment\ cost_{t,tech}$ = a power plant's specific investment cost per unit of installed capacity in year t (EUR/MW)

MW_{tech} = installed capacity of a power plant (MW)

Decommissioning of retired units

To prepare the energy location for new investments, coal-fired units must be decommissioned. The costs of dismantling units 1, 2 and 3 are assessed at EUR 5M, unit 4 at EUR 10M and unit 5 at EUR 14M (Žerdin et al., 2021, p. 94). In total, disassembling retired units would cost roughly EUR 29M.

Revitalisation of the cooling tower of unit 4

The cooling tower of unit 4, which is 93.75 m high and 63.5–88.97 m wide (width changes as the structure is hyperboloid), is to be revitalised in order to diversify activities, preserve the industrial heritage and reuse the existing constructions (Žerdin et al., 2021, pp. 213–218). The project would be undertaken jointly by the Municipality of Šoštanj and TEŠ, and its aim would be to repurpose the retired cooling tower into a business, educational, scientific, cultural, sporting and touristic centre with 18 floors. The first and second floor could be fixed and strengthened, and then transformed into a parking lot. The remaining part of the structure could have moveable floor slabs, which means that the height of individual floor could be adjusted to specific activities at any given time, for instance an Olympic-size swimming pool, diving pool, fitness, climbing wall, testing ground for civil defence, indoor athletics track, cinema, cultural and art exhibitions, research laboratories and other services where a vast, empty space is required. A restaurant and a sightseeing platform could be placed on top of the tower. The list of potential partners includes: Developmental Agency of SAŠA region, Educational Centre Velenje, Olympic Committee of Slovenia, Sports Association of Velenje, different local sports associations (e.g. Hiking Society Šoštanj), Tourist Association Šoštanj and various cultural and art organisations (e.g. the Museum of Velenje). TEŠ as a partial owner could use some storeys for its own research purposes in the field of green technologies and lease out the rest. Total costs are estimated at EUR 58.4M. It is assumed that TEŠ will claim a 20% share in the project, which amounts to EUR 11.7M. The Gasometer in Oberhausen, Germany, can be listed as a reference.

Batteries

As battery storage systems provide multiple benefits to the entire electric power system (see the subchapter 5.3 on batteries), it is sane to include them in the restructuring plan. Even more so because they are very well suited for providing aFRR, which would be lost after unit 6 is shut down, and their capital costs have been rapidly decreasing. If I build upon assumptions on capital expenditures for battery storage from Lazard (2018, p. 13) and Pietzcker, Osario and Rodrigues (2021, p. 4), assume 10 MW of in-front-of-the-meter (IFotM) battery storage with a capacity of 60 MWh (Lazard, 2018, p. 4), and use equation (2), total expenditures would amount to EUR 10M. More on the investment costs and the proposed future deployment of batteries in Slovenia can be found in subchapter 5.3.

Underground pumped storage hydropower plant Rudar

Pumped storage hydropower plants (PSHPP) currently represent almost 99% of all the on-grid storage capacities (Menéndez, Loredo, Galdo & Fernández-Oro, 2019, p. 1382). International Renewable Energy Agency predicts that their installed capacity could almost double by 2030 (in Menendéz at el. 2019). They store energy in times of high production and generate electricity in times of low production, exploiting high price spreads. Additionally, they contribute to the reliability of the system through supplying ancillary services, especially aFRR and mFRR. Since PSHPPs are frequently located in sparsely populated, hilly or mountainous landscapes where they exploit vast differences in height between upper and lower reservoirs, there are usually many environmental obstacles (e.g. Natura 2000) regarding PSHPPs and newly constructed high voltage electric lines connecting distant PSHPPs with transmission networks. Projects are thus often delayed or abandoned. That has been the case with PSHPP Kozjak (hereafter ČHE Kozjak) in Slovenia, which was shelved in the 2010s due to, among other reasons, local opposition and conservation concerns (Červek & Rubin, 2011). In the last few years, DEM has started to revive the idea. The project's future is thus highly uncertain, or as ELES has put it (ELES, 2019, p. 84), "its realisation is less probable". Returning to the framework delineated in the initial part of the master's thesis, a project that is less damaging to nature and more socially acceptable, has similar characteristics and is also more sensible in terms of a just transition and from a legal point of view does exit, which is why ČHE Kozjak has not been included in my decarbonisation plan. As an alternative, I propose an underground pumped storage hydropower plant (UPSHPP) Rudar (hereafter PČHE Rudar) within PV's mining structures. As will be described in the subchapter 4.5 on pumped storage hydropower plants, the installed capacity would be 225 MW, and the total investment costs would amount to EUR 382.5M (i.e. 1700 EUR/kW). The plant would generate 307 GWh of electricity per year and consume 403 GWh/year. It would provide ±45 MW of aFRR and ±22.5 MW of mFRR. One fifth of the project would be financed and subsequently owned by Green Shine or TEŠ and

PV, amounting to EUR 76.5M. The activities undertaken during the restructuring plan (2026–2027) and shortly after it would be funded by state aid. I assume that the power plant will be finished in 2032 (one year before the JEK2, which could partly depend on PČHE Rudar for ancillary services).

New heating system: utility-scale heat pumps and natural gas-fired CHP plant

As explained in-depth in the subchapter 4.4 on the future of the heating system, there are three possible ways forward for the heating system in the Šaleška valley and Slovenia as such: power-to-heat technologies (utility-scale heat pump, electric boiler), CHP stations running on biomass or on gas. Power-to-heat technologies, especially heat pumps, are viewed as highly beneficial and favourable for warmer months. However, during the colder months, the coefficient of performance (i.e. an expression of the efficiency of a heat pump calculated by comparing the heat output from the condenser to the power supplied to the compressor) of heat pumps, which also provide high-temperature heat to industries, falls below two, the pumps consume a large amount of electricity when already in short supply and expensive, and the coincidence factor, measuring simultaneous operation of all heat pumps, is high as well. This means that an unregulated and excessive deployment of heat pumps could cause great stress to the system in this time of year.

As for biomass or natural gas used in CHP plants, multifold arguments against biomass can be found in the subchapter 4.4 on heating, which leaves us with natural gas. Since natural gas is still a fossil fuel, hydrogen and synthetic natural gas, representing two low- or zero-carbon energy sources, are expected to fully replace natural gas in the Slovenian electric and heating power systems by around 2036 (see subchapter 5.4 on hydrogen and SNG). Additionally, a CHP plant generates most of the electricity and heat during the colder months and thereby contribute to the system's reliability and security.

In the Šaleška valley, heat is mainly provided by coal-fired unit 6. If unit 6 is under repair, coal-fired unit 5 and two gas-fired turbines cover the demand. As peak demand for heat is approximately 100 MW during the winter months, gas turbines can supply enough heat on their own. However, without coal, the system would rely solely on two gas turbines, which would profoundly aggravate the risk. I propose that the future heating system in the Šaleška valley is comprised of two types of power plants.

First, utility-scale air-water heat pumps would operate during the warmer months when the surrounding temperature is higher. Such examples already exist throughout the EU (European Heat Pump Association, n. d.).[12] The installed capacity of such heat pumps would

12 Even though there are mining lakes nearby with relatively stable water temperatures, which do not fall below 8°C during the winter (Agencija Republike Slovenije za okolje, n. d.), a water-water heat pump does not seem to be the most rational choice. A water-water heat pump is the most appropriate option if it operates throughout the year as water temperature is constant on annual basis. Since the proposed heat pump would run predominantly during the warmer months when the air temperature is higher than the water temperature, an air-water heat pump is a better alternative because it would reach a higher coefficient of performance.

be 12 MW, as peak demand during the warmer months is 30 MW, the average demand is significantly lower (correspondence with Municipal services Velenje), and the coefficient of performance is above two. To take advantage of the variability in electricity prices, enable demand-side responses and store heat for the upswings in heat demand, the construction of a short-term thermal storage system has also been envisioned. Seasonal storage has not been proposed as that would require new investments in most likely thermal solar panels and underground thermal energy storage or pit storage (International Renewable Energy Agency, 2019 pp. 10–11). Such options are attractive but excessively costly (Tavčar, 2021). Considering the data from IEA (2020, p. 420)[13] and employing equation (2), the total investment costs of utility-scale heat pumps the size of 12 MW and thermal storage system would amount to EUR 6.6M. Quarter of the project would be financed and subsequently owned by Green Shine or TEŠ and PV, amounting to EUR 1.6 M. Remaining part would be covered and managed by municipalities. During the colder months, the air-water heat pumps would not play the primary role but would function as a backup system, provide potential ancillary services and ensure additional security to the system.

Second, I propose a natural gas-fired CHP plant used primarily during the colder months and as a backup during the warmer months. Since peak demand reaches approximately 100 MW (conversation with a Municipal services Velenje employee) and it is assumed that a gas turbine would generate 26.5 MWh of electricity and 54.4 MWh of heat from 100 MWh of primary energy (Univerza v Ljubljani, Fakulteta za strojništvo, n. d.), the CHP plant would need roughly 50 MW of installed capacity. I have chosen a gas turbine instead of a steam turbine, as it produces more electricity and less heat from one unit of primary energy (Univerza v Ljubljani, Fakulteta za strojništvo, n. d.). This is vital because Slovenia and Europe will experience electricity shortages during winters if they do not invest in additional electricity-generating power stations. Another option would also be CCGT with waste heat usage (the case of TETOL). However, as the power plant would operate predominantly during the colder months, only CHP gas turbine seems economically more sensible. Using a 0.9 capacity factor (i.e. the ratio of actual energy produced over one year and maximum energy that could be produced over the same period) for the period of colder months (EIA, 2015) and equation (3), the CHP plant in the Šaleška valley would produce 227 GWh of electricity per year. Construction would be finished by the end of 2027.

$$MWh_{t,tech} = MW_{tech} * capacity\ factor_{t,tech} * 8765 \tag{3}$$

$MWh_{t,tech}$ = the amount of electricity produced by a power plant in year t (MWh)

MW_{tech} = installed capacity of a power plant (MW)

8765 = number of hours in one mean calendar year

13 IEA's capital costs only pertain to air source heat pumps in buildings. Since utility-scale heat pumps are proposed, it seems sensible to assume that the upper value also includes short-term storage capacity.

Capacity factor$_{t,tech}$ = ratio of actual energy produced over one year and maximum energy that could be produced over the same period for a power plant in year t (%)

Assuming the investment costs of 1675 EUR/kW, as the heating system is already set up (Vlada Republike Slovenije, 2020, p. 128), the total costs of a CHP station using a gas turbine with a capacity of 50 MW would amount to EUR 83.75M. I assume that the heat pumps, thermal storage and CHP station will be jointly owned by TEŠ and PV (25%) and the Šaleška valley's municipalities (75%).

Combined cycle gas turbines

As will be explained in the subchapter 4.6 on CCGT, Slovenia is expected to set up 285 MW of CCGTs by 2029. Two of them would be built in Šaleška valley. Considering the investments costs from IEA (2020, p. 419), total investment costs would amount to EUR 102M.

3.2.2.3 Summary

The projects are indispensable from the perspectives of the electric power system as a whole and of regional heating. Since they have been successfully deployed in other countries experiencing green transition, they are a relatively safe and low-risk. Last but not least, they can, to some extent, also provide new jobs opportunities for workers facing job losses due to the coal phase-out. Therefore, the projects listed above are envisioned to represent the backbone of the restructuring plan submitted to the EC. Table 8 summarizes the investments under the restructuring plan and its total costs, which amount to EUR 273M.

Table 8: Restructuring plan for TEŠ and PV from the 2026–2027 period – investment part (EUR M)

RESTRUCTURING PLAN 2026–2027 – INVESTMENT PART	
INVESTMENT	**INV. COSTS (EUR M)**
Solar parks	21.5
Decommissioning of retired units	29.0
Revitalisation of the cooling tower (1/5)	11.7
Battery storage system	10.0
PČHE Rudar (1/5)	76.5
Heating system (sum)	22.6
Utility-scale heat pumps (1/4)	1.6
CHP plant (1/4)	20.9
Combined cycle gas turbines	101.8
TOTAL	**273**

Source: own work based on Žerdin et al. (2021); International Energy Agency (2020); Lazard (2018) and Pietzcker, Osario & Rodrigues (2021).

3.2.3 Scope and funding sources for the restructuring plan of TEŠ and PV

If I add the capital costs of the investments under the restructuring plan (i.e. EUR 273M) to the EUR 331M of TEŠ losses in the 2027–2028 period, I get EUR 604M.

Where could the funds come from? The Just Transition Fund (JTF), established by the EU to support various European regions facing fossil fuel phase-out, ensures EUR 253M for Slovenia until 2027 (European Structural and Investment Funds, n. d.). As one of the main criteria for acquiring the resources is jobs created per money invested, capital-intensive energy investments will presumably be funded to only a small extent. I thus assume that three quarters of the costs for heating investments, solar parks, revitalisation of the cooling tower and batteries would be funded by the JTF and half of the costs for PČHE Rudar. JTF would therefore provide EUR 88M for the investments. The remaining part, namely EUR 517M, would be state aid in the form of loans and grants. A detailed specification of individual loans and grants is beyond the purpose of the master's thesis. Table 9 provides a summary.

Table 9: EU and state funds needed for the restructuring of TEŠ and PV (EUR M)

EU & STATE FUNDS (EUR M)	
JTF (sum)	88
Solar parks	16
Revitalisation of the colling tower	9
Batteries	7
Heating system	17
UPSHPP	38
STATE AID (grants & loans)	517

Source: own work based on European Structural and Investment Funds (n. d.)

The EC cannot approve state aid if an undertaking in difficulty does not make sufficient own contribution. Guidelines on State aid for rescuing and restructuring non-financial undertakings in difficulty are strict on this matter: "The amount and intensity of restructuring aid must be limited to the strict minimum necessary to enable restructuring to be undertaken … [and] a sufficient level of own contribution to the costs of the restructuring and burden sharing must be ensured. … Contributions must be real, that is to say actual, excluding future expected profits such as cash flow, and must be as high as possible. … Own contribution will normally be considered to be adequate if it amounts to at least 50% of the restructuring costs." (European Commission, 2014, pp. 12–13). In the above-mentioned Romanian approach (European Commission, 2021a, pp. 6–7), CE Oltenia's own contribution is a combination of two sources: first, electricity futures and long-term bilateral power purchase agreements[14] and second, the sale of different assets. The same approach, adjusted for PV's role as the sole coal retailer to TEŠ, could be used in my case.

Regarding futures and long-term bilateral power purchase agreements, I have predicted that in 2025 (i.e. before the start of the restructuring period), TEŠ would sell 97.5% of its front-year and two-year ahead power output. For comparison, in 2018, RWE sold 90% of its front-year and two-year ahead power output (Demirdag, 2018). My assumption is higher than RWE's, but the context is entirely different. Futures sold by the end of 2025 are a prerequisite for presenting a fixed future cash flow to the EC. Therefore, it could be realistically assumed that the HSE Group and SDH would pressure TEŠ into selling as much future electricity as possible by the end of 2025. Using the price of electricity calculated above, TEŠ would hold EUR 410M of fixed future cash flow in 2025.

Since PV is the sole coal provider to TEŠ, the quantity of coal required to generate electricity sold on the futures market can be perceived as PV's fixed future cash flow, which would amount to EUR 79M in 2025 based on the coal price calculated above.

Additional own contributions can come from selling off the shares in other firms and subsidiaries. TEŠ has no notable assets in other enterprises, whereas PV has full control over HTZ I. P., PLP and Sipoteh (not taking into consideration RCE, which has gone bankrupt, and a 4% share in RGP) (HSE, 2020, p. 52). Considering the EBITDA of the companies (HSE, 2020, p. 66), the share of income dependent on the PV Group (i.e. PLP approximately 75%, Sipoteh roughly 90%), the advice from an expert with an in-depth knowledge on PV, and using EBITDA valuation method to calculate the values of enterprises, Sipoteh, HTZ I. P. and PLP could be sold at the price of EUR 3M, 12.5M and 2.5M, respectively. The total sale price would thus amount to EUR 18M. As more than 50% of HTZ I. P. employees are disabled, I propose that the HSE Group buys HTZ I. P by exerting the pre-emptive right as a full owner of PV. With such a move, I would stick to the social pillar, take care of people with disabilities and secure support from the trade unions. HTZ I. P. would provide maintenance and repair work to the HSE Group and thus retain the same role as it currently holds within the PV Group.

In total, the fixed future cash flow of TEŠ and PV combined would reach EUR 507M in 2025 (Table 10).

14 EC voiced some concerns about such funds, but its remarks pertain to the holes in Romanian legislation and not to the approach *per se*.

Table 10: Fixed future cash flow of TEŠ and PV in 2025 (EUR M)

FIXED FUTURE CASH FLOW IN 2025 (EUR M)	
TEŠ	410
PV – coal	79
PV – sale of assets	18
Total	507

Source: own work based on EEX and HSE (2020).

Table 11 summarizes the overall restructuring plan of TEŠ and PV. It would total EUR 1,111M, of which fixed future cash flow of both enterprises amounts to EUR 507M, just transition fund to EUR 88M and state aid to EUR 517M.

Table 11: Total costs of the restructuring plan of TEŠ and PV (EUR M)

RESTRUCTURING PLAN 2026–2027	
ACTIVITY	**COST (EUR M)**
RESTRUCTURING PLAN	**1111**
Investments	273
TEŠ&PV loss	331
TEŠ&PV fixed future cash flow	507
CONTRIBUTIONS	**1111**
TEŠ&PV fixed future cash flow	507
JFT	88
State aid	517

Source: own work.

Since the guidelines state that "own contribution will normally be considered to be adequate if it amounts to at least 50 percent of the restructuring costs" (European Commission, 2014, p. 13), the shares of different actors are calculated in Table 12. In both cases, including and excluding the JTF, state aid does not surpass 50%, making it compatible with the EC's demand.

Table 12: EU, state and private contributions in the restructuring plan of TEŠ and PV

CONTRIBUTIONS			
TYPE	**COST (EUR M)**	**SHARE (incl. JTF)**	**SHARE (excl. JTF)**
TEŠ&PV contribution	507	0.46	0.50
JTF	88	0.08	
State aid	517	0.46	0.50
Combined	1,111	1.00	1.00

Source: own work.

3.2.4 Public funds required for a safe closure of coal-related objects and broader socio-economic restructuring of the region

Besides the state aid that will be use to prolong the termination of TEŠ and PV, additional funds will be required for decommissioning and a technically safe closure of coal-related objects on the one hand, and a socio-economic restructuring of the region on the other. It is beyond the scope of the master's thesis to formulate such a plan in detail. Nevertheless, the social pillar of green transition is crucial, and since my plan is to assess the amount of all decarbonisation costs, I will briefly discuss the topic in the following section.

The investments described above that pertain to the restructuring plan of TEŠ and PV can complement the funds for regional restructuring, but are not sufficient. Mostly capital-intensive energy investments cannot generate enough job opportunities and regional developmental options for the valley, where roughly 3,500 workers are indirectly or directly attached to the mining and electricity sector and where coal-related activities generate approximately a third of total local revenue (Deloitte, 2021, p. 8). Once the National Strategy for Phasing Out Coal is adopted, the Ministry of Economic Development and Technology will prepare the Law on the Restructuring of the SAŠA region, and the Ministry of Infrastructure will prepare the Law on the Gradual Closure of PV. As of November, 2021, the strategy has not been passed yet, both drafts are unavailable at best or non-existent at worst. Unfortunately, the latter seems more probable, especially regarding the Law on the Restructuring of the SAŠA region (Pirc, 2021). The Action Plan for Savinjsko-Šaleška Coal Region in Transition (Deloitte, 2021), prepared by Deloitte and funded by the EC to accelerate the transition, is not very helpful either.

Based on the information acquired in private conversations with experts familiar with the situation in PV and the fact that the technical part of the closure of the smaller and less complex Coalmine Trbovlje-Hrastnik (RTH) will cost approximately EUR 225M (correspondence with a former RTH employee), I assume that EUR 500M EUR are needed to close the mine safely. These funds would be allocated from the state budget since PV does not have sufficient means to carry out the necessary activities. Under Slovenian and European environmental law, especially the polluter pays principle, PV should – similar to Nuclear power plant Krško – secure adequate funds during its operation to terminate its activities safely. By not making such continuous contributions, PV has artificially reduced its costs and inflated its apparent profitability. In consequence, even though state aid is necessary for closing the mine, it should be perceived as legally dubious.

I estimate that EUR 1,000M are needed for a socio-economic restructuring of the SAŠA region, including EU, state and private means and not taking into account the investment part (EUR 273M) of the restructuring plan of TEŠ and PV. This estimation is based on private discussions with state and local actors and some figures presented below. First, when Deloitte was preparing the action plan and identifying projects for potential funding through the JTF mechanism, Deloitte received more than 103 project ideas. The best proposals would generate 1,100 jobs and cost EUR 400M (Časnik Finance, 2021), combining own, state and EU funds (the exact shares were not given). Second, the Regional Developmental Plan of the SAŠA Region for the 2021–2027 Period (Razvojna agencija Savinjsko-Šaleške regije, 2021, pp. 233–244) lists all the projects from public and private actors that could contribute to a just transition of the region. If all were realised, the total costs would top EUR 1,123M. However, the share of own funds, effects on employment, project maturity, relevance, funding eligibility, alignment with various EU and state strategies, and other aspects are not defined in the plan. Third, as regional employers, Chamber of Commerce representatives and other actors have pointed out (Časnik Finance, 2021; Pirc, 2021), large regional employers (BSH Nazarje, Gorenje, Plastika Skaza, TAB Mežica, Podkrižnik group etc.) are looking for new technical workers. Small and medium-sized enterprises could also play a bigger role in the future as the rate of employment in such regional firms is below the national average (Deloitte, 2021, p. 19). Nevertheless, the "natural" job demand of various companies would not suffice (Časnik Finance, 2021). Therefore, state aid will be needed to stimulate additional employment opportunities and provide adequate reskilling and upskilling programmes for the unemployed. Fourth, even though energy projects are capital-intensive, EUR 273M of investments within the TEŠ and PV restructuring plan would create new, quality jobs and contribute to the green development and job opportunities in the region. These expenditures would come on top of EUR 1,000M mentioned above. Finally, the proposed amount is unimaginably higher than approximately EUR 30M of state funds allocated for the socio-economic restructuring of RTH, which had 1333 employees at the onset of closure in 2000 (correspondence with a former RTH employee).

To conclude, roughly EUR 1,500M of EU, state and private funds would be required to close coal-related objects in a technically safe manner and ensure a socially and economically just transition of the region. To be more specific, EUR 500M would be assigned to the first objective and EUR 1,000M to the second one. The closure of coal-related objects would be financed entirely from state funds, and the socio-economic restructuring from EU, state and private resources. More precisely, EUR 400M could come from EU funds, especially the Just Transition Fund, Cohesion Fund, European Social Fund and European Regional Development Fund (conversation with one of the experts). Such backing hinges on the early closure date and local municipalities' readiness to abide by strict EU rules. Assuming that on average 30% of a project's total investment expenses come from own funds (the minimum is 15%; one of the experts mentioned that the share could realistically be elevated up to 50%), private contributions would amount to EUR 300M (Deloitte, 2021, pp. 49–59). The remaining EUR 300M would come from state aid. Four fifths of state funds would be spent by the end of 2030 and the remnant by 2040 since some closing works would last 10–15 years (Mestna občina Velenje, 2021). Combined with the investment part under the TEŠ and PV restructuring plan, total funds for the closure of coal-related objects and restructuring of the SAŠA region would add up to EUR 1,773M (Table 13).

Table 13: Total costs for the restructuring of the Šaleška valley (EUR M)

RESTRUCTURING OF THE ŠALEŠKA VALLEY (EUR M)	STATE FUNDS	EU FUNDS	OWN FUNDS	TOTAL
Investment part - PV&TEŠ	185	88		273
Closure of coal-related objects	500			500
Socio-economic restructuring of the region	300	400	300	1,000
TOTAL	**985**	**488**	**300**	**1,773**

Source: own work based on conversations with experts; Časnik Finance (2021); Razvojna agencija Savinjsko-Šaleške regije (2021) and Deloitte (2021).

Total EU, state and own funds for the region, TEŠ and PV would amount to EUR 2,611M (Table 14). As EUR 2.6 billion presents a high figure for one region, it probably marks an upper limit of available funds. However, these funds assure socially just and technically safe restructuring of the region and are thus indispensable for any thorough decarbonisation plan. Moreover, considering that funds would gradually pour into the area throughout the 2022-2040 period and would come from the state, EU and private actors, the size seems much more modest and manageable.

Table 14: Total costs for the restructuring of the Šaleška valley, TEŠ and PV (EUR M)

TOTAL COSTS OF THE RESTRUCTURING OF THE ŠALEŠKA VALLEY, TEŠ AND PV (EUR M)	
SOCIO-ECONOMIC RESTRUCTURING OF THE REGION	1,000
CLOSURE OF COAL-RELATED OBJECTS	500
TEŠ & PV RESTRUCTURING PLAN	1,111
TOTAL	**2,611**

Source: own work.

3.2.5 TEŠ's EIB loan with government-backed guarantee

TEŠ took out a EUR 440M government-guaranteed loan from the European Investment Bank (EIB) to finance the construction of unit 6 (Termoelektrarna Šoštanj, 2014, p. 149). In 2028, the principal will still amount to EUR 214.9M (Termoelektrarna Šoštanj, 2014, p. 229). Based on the restructuring plan described above, I assume that TEŠ would become profitable again and could cover the rest of the loan by itself. However, if repaying the loan presented an excessive burden for the company, the state would need to cover the costs.

3.3 Phase-out of coal-based generation in CHP plants in Ljubljana and other locations

Besides TEŠ, TETOL and some other CHP stations around the country have also been burning coal to generate heat and electricity. It is assumed that coal phase-out in TETOL will happen by the end of 2029, one year earlier than proposed in the NECP (Vlada

Republike Slovenije, 2020, p. 58). The same predictions have been made for other CHP plants that burn coal. If so, Slovenia's electric power system would be coal-free by 2030. As shown in the subchapter 4.4 on CHP stations, natural gas and alternative sources (RES, waste heat, etc.) would predominately substitute coal in the heating system. By around 2036, natural gas would be decarbonised through hydrogen and synthetic natural gas. The coal phase-out timeline resonates with my climate pillar as, according to a study by Climate Analytics (2019), OECD countries should phase out coal by 2031 at the latest to comply with the Paris Agreement.

3.4 Phase-out of natural gas in the electric power system and CHP part of the heating sector

Decarbonisation of natural gas in the electric power system and CHP stations will be tackled and examined in the subchapter 5.4 on hydrogen and synthetic natural gas. Calculations show that natural gas will be entirely replaced by domestically produced hydrogen and synthetic natural gas by around 2036.

4 NEW POWER PLANTS AND ENERGY SOURCES FOR THE 2022-2040 PERIOD

4.1 Solar power

Solar energy is one of the most important future energy sources. Since my plan does not envision any new big hydropower plants due to conservational concerns (see subchapter 4.3 on HPPs) and wind power plants could bring only 313 MW (see subchapter 4.2 on WPPs), solar energy should play an important role in future decarbonisation efforts. As outlined in the NECP (Vlada Republike Slovenije, 2020, p. 142), "electricity generation from solar power plants carries the largest developmental and environmentally acceptable potential for the enlargement of electricity production from renewable energy sources in Slovenia". Additionally, as observed in Table 2, solar power stations have a similar carbon footprint to NPPs and WPPs and lower carbon footprint than HPPs and biomass-fired power plants. Moreover, their biodiversity footprint is bearable, especially if sited outside the protected areas (Figure 2). On the other hand, solar cannibalism (López Prol, Steininger & Zilberman, 2020), where the value of SPPs is undermined as a consequence of their own increasing penetration, high system costs, examined and calculated in the subchapter 5.1 (see also International Energy Agency, 2020, pp. 239–40, 419), and other downsides of this technology should be taken into account. A sensible plan can only emerge if we consider both the advantages and the disadvantages of solar energy.

4.1.1 Total installed capacities, electricity generation and investment costs

Table 15 shows different projections for solar power capacity in 2025, 2030, 2035 and 2040 that were given in the NECP (Vlada Republike Slovenije, 2020, p. 142), the ambitious RES scenario (eucogreensn) by the Energy Concept of Slovenia (hereinafter ECS+) (European Commission, 2016, p. 154), the ambitious solar scenario from the Consortium for Promotion and Acceleration of Green Transformation, led by ELES and GEN-I (appointment with a GEN-I employee), and the predictions prepared by Slovenian Academy of Sciences and Arts (SAZU, 2022). As the NECP was prepared before the EU had agreed upon higher climate targets and the share of RES in the overall EU energy mix, its goals are not ambitious enough and should be revised. On the other hand, very high installed solar power capacities, especially in the ECS+ scenario, would entail immense system costs. My proposal, which is based on the system costs calculations (partially shown in subchapter 5.1) and the impacts of various solar scenarios on the future energy balance (the most sensible one can be seen in the subchapter 6.1), is presented alongside the other scenarios. The capacities estimated in my scenario are roughly in line with the ones proposed by the Consortium and by Slovenian Academy of Sciences and Arts and Slovenian Academy of Engineering.

Table 15: Future solar power capacities predicted by various institutions (MW)

SOLAR POWER CAPACITY (MW)	2025	2030	2035	2040
NECP	900	1,650	2,950	4,400
ECS+	1,983	2,758	3,867	7,168
Consortium	950	2,900	4,900	5,650
SAZU	1,260	3,230	5,130	5,980
Ostan Ožbolt	1,000	3,000	4,750	6,000

Source: own work; EC (2016); Vlada Republike Slovenije (2020); appointment with a GEN-I employee and SAZU (2022).

Table 16 additionally presents electricity generation of proposed solar power stations that was calculated using the capacity factor of 0.117 and equation (3) (Mervar, 2019a).

Table 16: Capacities and generation of solar power plants in the 2020–2040 period

SOLAR POWER PLANTS	2020	2025	2030	2035	2040
INSTALLED CAPACITY (MW)	372	1,000	3,000	4,750	6,000
GENERATION (GWh)	381	1,026	3,077	4,871	6,153

Source: own work based on Mervar (2019a).

I assume four solar project types (Lazard, 2020): SPP on a rooftop of a single-house; SPP on the rooftop of a commercial, industrial or institutional object; a community-scale solar park; and a utility-scale solar park. Future investment costs that are presented in the Table 17 are calculated based on the investment costs given in the NECP, adjusted upwards, for the first three types (Vlada Republike Slovenije, 2020, p. 128). IEA's European Sustainable Development Scenario (2020, p. 419) provides the data for the costs of utility-scale solar parks.

Table 17: Investment costs by solar project type in the 2020–2040 period (EUR/kW)

INV. COSTS BY PROJECT TYPE (EUR/kW)	2020	2025	2030	2035	2040
ROOFTOP HOUSEH.	1234	1099	963	915	867
ROOFTOP COM.&IND.&INST.	1191	1060	929	883	837
COMMUNITY	1098	977	857	814	772
UTILITY SCALE	733	648	563	478	393

Source: Vlada Republike Slovenije (2020) and International Energy Agency (2020).

4.1.2 Installed capacities and solar project types

4.1.2.1 Utility-scale solar parks

Utility-scale solar parks present the most sensible solar project type from the economic and technical points of view (Babič & Damijan, 2020), but could have negative impacts on nature. They would be primarily connected to 110 kV electric lines of the transmission network. There are currently two transformer substations that can take in less than 100 MW of vRES and 21 transformer substations that can bring in more than 100 MW of vRES (ELES, 2021, pp. 2–3). Considering mutual dependency where installed capacities at one substation can reduce the available installed capacity at the other (ELES, 2021, p. 3), it is assumed that each substation could secure on average 65 MW of vRES without additional upgrades. In total, the Slovenian transmission network could connect 1495 MW of vRES without extra improvements. Such a plan would require state-led, coordinated action where investors would be directed predominately to these transformer substations, which would secure enough time to upgrade the transmission network for additional energy projects. Since utility-scale solar parks are sensible from technical and economic points of view, I propose an additional 1,367 MW of solar power plants until 2040. These would require reinforcements, upgrades and, in some cases, new transmission lines. In total, utility-scale solar parks would amount to 2,862 MW or 48% of total solar power capacities by 2040. For comparison, Babič and Damijan (2020) propose 4000 MW or 80% of overall solar power capacities connected to the transmission network.

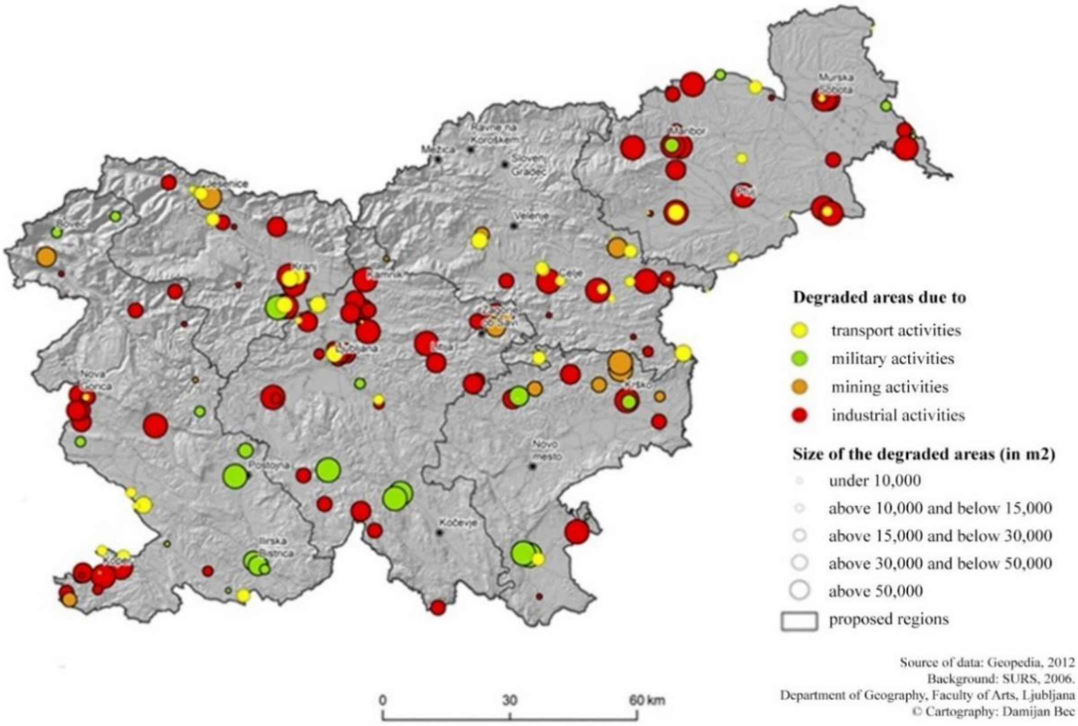
What would the impacts on nature be? If I assume that 1.9 ha of land is needed for a utility-scale solar park to generate 1 MW with the existing 19% solar panel efficiency (Semprius, 2021) and that the latter will increase to 21% and 22.5% by 2030 and 2040, respectively (Kovač, Urbančič & Staničić, 2018, p. 23), the above-mentioned solar power stations will take up 48.8 km^2 or 0.24% of the country's surface. It seems likely that with sensible siting and active participation of various agencies and experts for nature conservation such projects could be implemented without any noticeable adverse effects on biodiversity, ecosystems and nature as such. Additionally, a study should be conducted to identify technically suitable locations for utility-scale solar parks outside the exclusion zones. Analyses on wind power plants (see subchapter 4.2 on WPPs) and on small hydropower plants (see the subchapter 4.3.3 on sHPPs) can be used as a reference.

4.1.2.2 Solar power plants on degraded lands and parking lots

Degraded lands (Figure 5) and parking lots (Figure 6) are a valuable location for solar parks. First, these areas are usually vast (Lampič, 2012; Agencija Republike Slovenije za okolje, n. d.; Bole, 2015, p. 23), meaning that construction on such land could reach economies of scale and thus lower investment costs per kW. Second, as almost all degraded lands or parking lots are situated inside agglomerations or on their outskirts and not in the countryside (Lampič, 2012; Agencija Republike Slovenije za okolje, n. d.; Bole, 2015, p. 23), the costs of connecting and upgrading the network would be lower compared to other options. What is more, three quarters of existing degraded lands are currently at least partly used by new or old industries (Lampič, 2012; Agencija Republike Slovenije za okolje, n. d.), and degraded lands are frequently adjunct to industrial objects, which have a favourable overlap between their energy consumption and energy generation from SPPs (Kovač, Urbančič & Staničić, 2018, p. 26), thus enabling on-site use of electricity. Additionally, electricity-generating parking lots could provide electricity on-site to charge electric vehicles (EV), further reducing the need for grid reinforcement. Lastly, covering degraded lands and parking lots with solar panels would not cause any tangible adverse effects on biodiversity and ecosystems, and is therefore acceptable from the perspective of nature conservation.

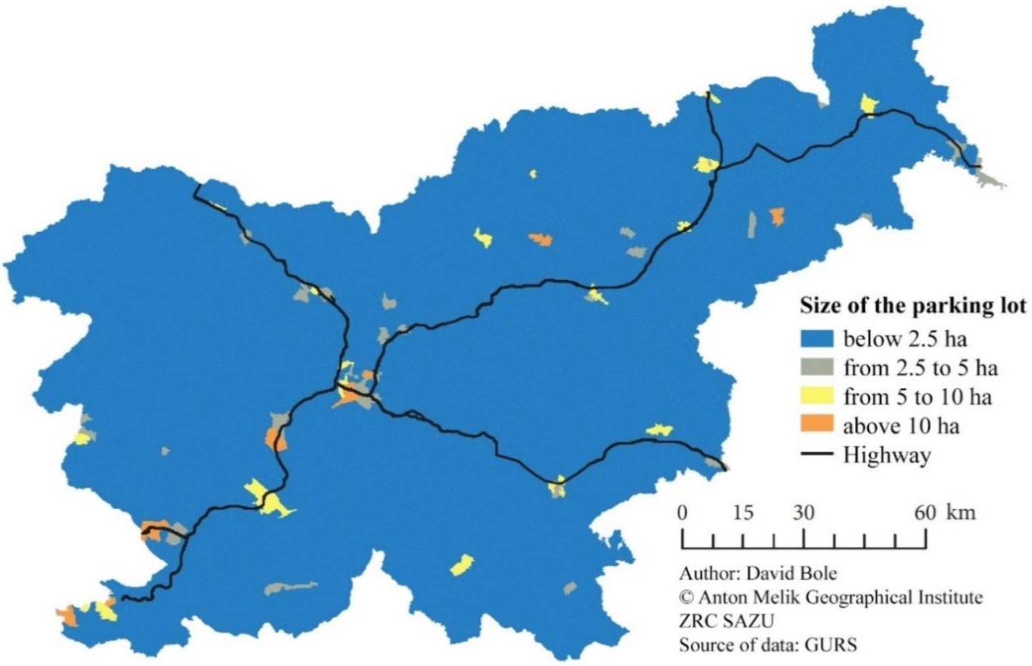
Using data from Kovač, Urbančič and Staničić (2018, pp. 19, 38-39) and assuming less than a third of degraded areas and parking lots covered with SPPs by 2040, I envision 554 MW of solar power stations sited on these locations by that date. Such projects would represent 9% of overall installed solar power capacity and generate 568 GWh of electricity. I assume that 80% of solar parks on degraded lands and parking lots would be community-sized solar power plants and 20% utility-scale plants.

Figure 5: Map of degraded areas by type and size in 2011



Adapted from Lampič (2011).

Figure 6: Map of parking lots by municipalities and size in 2011



Adapted from Bole (2015).

4.1.2.3 *Solar power stations on the rooftops of industrial, commercial and institutional objects*

The third sensible option are rooftops of industrial, commercial and institutional buildings. First, it is economically more sensible to install solar panels on these constructions because they are wider than family houses and blocks of flats. Second, if we compare households, industry and administration in terms of the level of overlap between electricity generation from SPPs and on-site electricity use, we see that industry, especially where there is no shift work, fits this model best, followed by administration (Kovač, Urbančič & Staničić, 2018, p. 26). It would be sensible to install charging stations for EVs at some of these locations (depending on their energy-consumption profile) to additionally use the electricity on-site. Even more, the nearby residents charging their EVs at these stations in the afternoon would soften the drop in consumption when the sun still shines, which would benefit the entire network (Vojsk, 2018, pp. 28–29; Kovač, Urbančič & Staničić, 2018, p. 26).

The results from the study conducted by the Centre for Energy Efficiency at Institute Jožef Stefan show that the technical potential of solar power stations installed on appropriate rooftops in Slovenia is roughly 26.5 TWh (Kovač, Urbančič & Staničić, 2018, p. 39), of which 9,264 GWh could come from industrial, commercial and institutional buildings, since these represent 35% of all rooftop areas (Kovač, Urbančič & Staničić, 2018, p. 16). In terms of power, that amounts to roughly 9,033 MW. In my decarbonisation plan, I assume that roughly 15% of such technical potential would be used by 2040. More specifically, that translates into 1,385 MW of SPPs sited on industrial and commercial buildings and an annual generation of 1,420 GWh.

4.1.2.4 *Solar power stations on the rooftops of single-family houses, community solar projects and energy democracy*

The constructions mentioned above would be more extensive, coordinated by public and private institutional investors, thus reaping the benefits of economies of scale and not imposing all of the transition's efforts (and blame) on ordinary citizens. Additionally, by proposing larger solar parks constructed by public and private institutional actors, it is easier to envision the operational and executive capabilities to carry out such a substantial increase in solar power plants.

The fourth option for setting up solar power stations are single-family houses with smaller solar power capacities and energy communities where more households come together, collectively organize and set up bigger solar power plants on their block, suitable nearby building, in the countryside or on the outskirts of the city. From a narrow economic perspective, such solar parks are not the most sensible solutions because they are smaller and thus more expensive per kW (Table 17). Anyhow, by broadening our perspective, such projects become economically viable due to three main reasons. First, the cost of a green transition will be high and different funds and actors will need to be mobilised. Every additional resource will be helpful. As Slovenian households own approximately EUR 23 billion of deposits on bank accounts (STA, 2021) (and inflation has been on the rise, pushing clients towards other financial options), it would make sense to tap into such an abundant resource. Second, as solar panels provide decent but not the highest profit margins, require longer-term investment horizons, not short-term speculative ones, and as the solar panels are still not fully mature, it is even more valuable to activate households, which in general give greater weight to non-economic factors compared to enterprises and frequently have access to a lower cost of capital (Pollin, 2012, pp. 349–50; Bolinger, 2001; Bolinger, 2005). Third, as household and community-based renewable energy projects provide electricity independence for part of the year, they can enjoy more price stability than other non-generating consumers (Pollin, 2012, p. 351).

From the perspective of an electricity network, the overlap between the electricity generated from a solar power plant and a consumption profile is worse for households than it is for industrial or other users, which causes specific problems for system operators. Slovenia's dispersed settlement structure means that the size of the distribution network per user is 82% higher than the EU average, only aggravating future challenges and obstacles. Furthermore, the existing net metering scheme reduces the essential money flow to the operators and unjustifiably gives equal weight to home-generated electricity during summer months and consumed electricity during winter months. The scheme also does not stimulate households to set up their own storage facilities and thereby shifts the necessary adjustments and system costs on system operators. However, contemporary technologies (e.g. EVs, home batteries) and approaches (e.g. demand-side management) can at least partly address and resolve these issues. Additionally, community-based solar parks have one important benefit vis-à-vis bigger utility-scale projects. As they are smaller, they can be sited closer to agglomerations, reducing the need to upgrade or build new electric lines (Pollin, 2012, p. 351). From the perspective of nature conservation, solar panels owned by households and community-based solar projects are in most cases situated on the rooftops or on the outskirts of the city and do not contribute to the biodiversity crisis. As for the social justice pillar, it is essential that energy citizens and energy communities are mobilized, empowered and encouraged to become active citizens, by which power can be taken from big corporations and conferred on ordinary people. Combined with the democratization of the provision of other essential goods and services (e.g. food, housing, mobility), energy democracy can represent one of the main drivers of doughnut economics and an essential lever for reaching a long-term goal – a good life for all within planetary boundaries (i.e. living within the doughnut) (Raworth, 2017). Last but not least, such projects face little local opposition and avoid the not in my backyard effect, since they bring tangible and intangible benefits to people and communities; for example, profits stay within the local communities and support local development, communities become more united and their members develop a sense of worthiness and acceptance etc. (Pollin, 2012, p. 351). Consequently, a green transition gains more support among ordinary people and is accelerated.

Naber and co-authors (CE Delft, 2021) assessed the potential of generating electricity from distributed energy resources in the hands of local communities, households, municipalities and small and medium-sized enterprises. They estimated the potential for single-family households in Slovenia at 1085 GWh (1058 MW) by 2030 and 2514 GWh (2451 MW) by 2050, and the potential for roof- and ground-based SPPs owned by local collectives at 458 GWh (447 MW) by 2030 and 1061 GWh (1034 MW) by 2050. In my decarbonisation plan, I assume that single-family households and energy communities will cover the remaining part of the predicted installed capacity, i.e. 1200 MW, by 2040. This represents slightly less than 50% of the overall technical potential for 2040. That same year, they would jointly generate 1,231 GWh of electricity. I assume that 70% of the suggested solar panels will be installed on single-family houses, 20% on industrial, commercial and institutional buildings and 10% will represent community-sized solar parks.

SPPs on degraded lands, parking lots, industrial, commercial, institutional and household rooftops and community solar projects would be connected to the distribution network; by 2030, their installed capacity would amount to 1569 MW. The feasibility of such a proposal is underlined by the NECP itself, which envisions 1650 MW of solar power stations connected to such a network by the same date (Sistemski operater distribucijskega omrežja, 2020, p. 36).

4.1.3 Summary

The presented data is summarized in the Table 18. We can see that utility-scale solar parks would represent 48% of all installed solar power capacities in 2040, SPPs on industrial, commercial and institutional buildings 23%, solar panels on single-family households and community solar projects 20% and lastly, solar energy capacities on degraded lands and parking lots 9%. The picture is somewhat different when costs are taken into account, as spreads are narrower, which further proves that the proposed approach is economically sensible.

Table 18: Solar power plants in 2040: capacity, generation and costs

SOLAR POWER in 2040	CAPACITY (MW)	SHARE	GENERATION (GWh)	TOTAL COSTS 2022–40 (EUR M)	SHARE
UTILITY-SCALE SOLAR PARKS	2,862	48%	2,935	1,567	38%
DEGRADED LAND & PARKING LOTS	554	9%	568	449	11%
IND., COM. & INST. BUILDINGS	1,385	23%	1,420	1,096	27%
HOUSEHOLDS & COMMUNITIES	1,200	20%	1,231	982	24%
TOTAL	6,000	100%	6,153	4,094	100%

Source: own work based on Vlada Republike Slovenije (2020); International Energy Agency (2020) and Mervar (2019a).

4.2 Wind power

The most in-depth analysis of the realistic and realizable potential of wind power plants in Slovenia was done by Mlakar and co-authors (Aquarius, 2015b), who took into account both the wind conditions (i.e. economic perspective) as well as the social and nature conservation aspects. Only the areas with a wind speed of over 4.5 m/s at the height of 50 m above ground level were considered. The following social issues were included: only territories that are located at least 800 m from communities or 500 m from single houses were deemed appropriate. Cultural heritage and landscapes protected under the Cultural Heritage Protection Act and the Spatial Planning Strategy of Slovenia were designated as exclusion zones. Lastly, in regard to the nature protection, a broad range of nature conservation legislation (Nature Conservation Act, Rules on the designation and protection of natural values etc.) was considered when identifying the exclusion areas. Scientists identified twelve vast areas of 133 km^2 in total that meet these conditions.

Installed capacities of wind power plants in these territories would range from 330 to 480 MW (Aquarius, 2015b, p. 31). If I assume the capacity factor of 0.183 (Aquarius, 2015b, p. 31) (NECP uses a slightly higher value, i.e. 0.19 (Vlada Republike Slovenije, 2020, p. 143)) and employ equation (3), such power stations would generate from 528 to 768 GWh of electricity. As wind power plants are becoming bigger and more advanced, it seems sensible to take 480 MW as the starting point.

Researchers from the Slovenian Bird Watching and Research Society (DOPPS) overlapped the identified territories of the study mentioned above with the areas that are essential for bird conservation (Bordjan, Jančar & Mihelič, 2012). These are defined as bird congregation areas, locations of bird reserves and regions where sensitive and rare birds reside. The authors concluded (Bordjan, Jančar & Mihelič, 2012, p. 4) that 7.1% of the areas identified as wind energy sites overlapped with areas of high importance for birds, and 25.7% of proposed areas overlapped with regions of medium importance for birds. This means that more than two thirds of the wind energy potential identified by Aquarius (2015b) is unrelated to areas essential for bird protection. More precisely, the authors propose that Porezen, Rogatec-Črnivec-Ojstri vrh and Golte[15] be removed from the list of potential wind energy sites altogether and call on investors to avoid the most sensitive parts of some other locations. If I reduce the capacity potential mentioned earlier for those three areas and apply an additional 5% reduction, the wind energy potential in Slovenia amounts to 336 MW.

The economic aspect is implicitly included in the studies above as only the areas with an average wind speed of over 4.5 m/s at the height of 50 m above ground level are taken into account, which is deemed as sufficient velocity to make investment economically viable (US Department of Energy, 2008; Aquarius, 2015b, p. 29). However, the studies mentioned above do not cover the technical perspective of the electricity network even though most of the suitable locations are situated in mountainous or hilly territories, far away from the electrical grid strong enough to receive such significant amounts of electricity. The inadequate network currently presents one of the main obstacles in wind power deployment. Mervar (2021) describes two occasions where investors were keen to construct three wind and solar parks with a combined capacity of 400 MW but gave up because ELES was not able to obtain building permits for new transmission lines. Moreover, setting up a robust network for each and every potential site would not be sensible from broader economic and nature conservation points of view. From the investor's narrow perspective, constructing a transmission line to its power plant does not incur any additional expenses. From a broader, system-wide perspective, the benefits of one wind park could be lower than financial, environmental and other costs for building such a line. They could generate net costs, not net benefits. In terms of the nature conservation pillar, it is very likely that ELES and electricity distribution companies will not obtain the construction permits for all the required power lines. Thus, I presume that 85% of the identified wind energy potential could be reached. More precisely, I identify ten wind parks with a total capacity of 283 MW. These farms would generate 476 GWh of electricity. Their locations and capacities are presented in Table 19 and Figure 7. Some sites are appropriate for wind parks with high capacity density and bigger wind turbines (A). Others are suitable for wind farms with low capacity density and smaller wind turbines due to nature conservation or/and social limitations (B). Most of these projects would be funded and carried out by institutional investors, whereas local communities could manage some smaller areas.

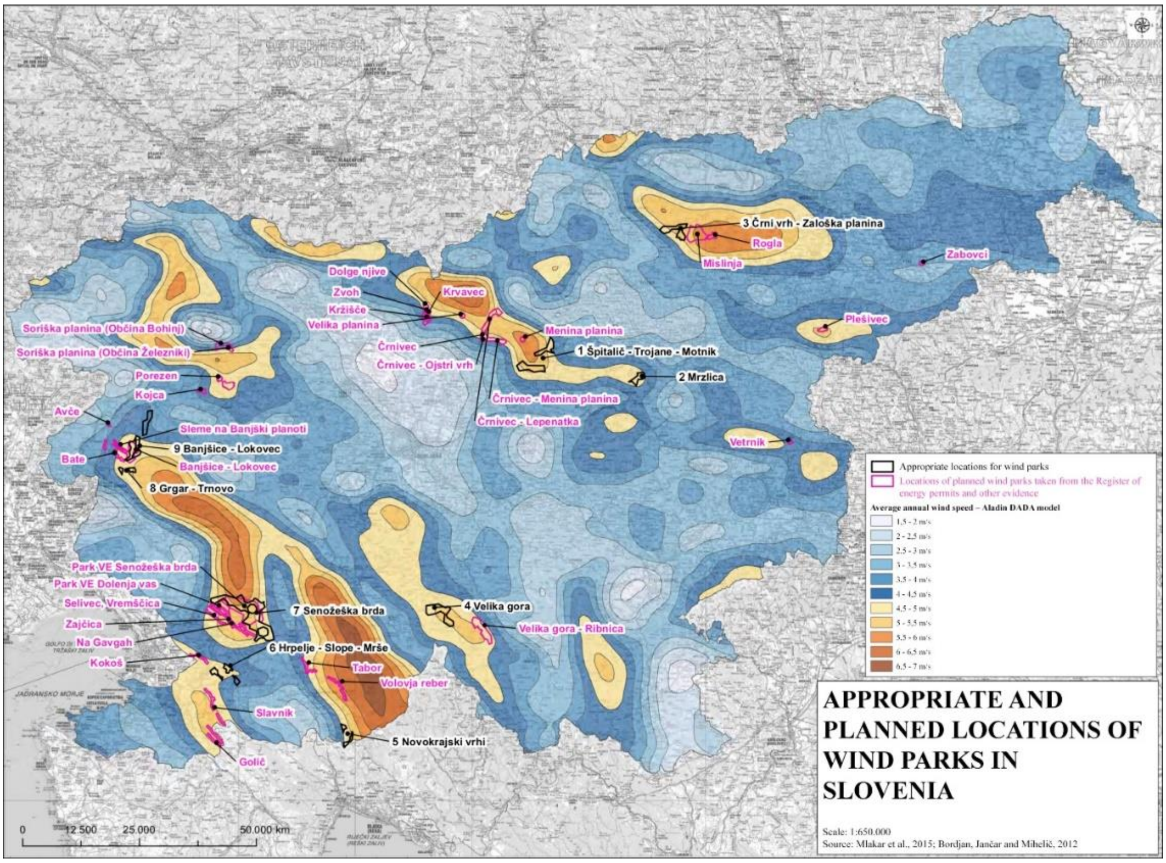
15 They also propose partly discharging Senožeška brda-Vremščica-Čebulovica-Selivec. As scientists refer to the 2011 version, which included more extensive territory for this location, whereas the updated version from 2015, used and presented in this chapter, already cut out the most contentious part, further adjustments of this area are not applied.

Table 19: Proposed locations of winds parks by 2035

LOCATIONS OF WINDS PARKS	LOCATION TYPE	POTENTIAL SIZE (km²)	CAPACITY (MW)
Špitalič-Trojane-Motnik	B	13	31
Mrzlica	B	4	10
Črni vrh-Zaloška planina	B	8	19
Velika gora	A	11	39
Novokrajski vrhi	A	2	7
Hrplje-Slope-Mrše	B	5	12
Senožeška brda	A	35	124
Grgar-Trnovo	B	2	5
Banjšice-Lokovec A	A	4	15
Banjšice-Lokovec B	B	9	22
TOTAL		93	283

Adapted from Bordjan, Jančar & Mihelič (2012) and Aquarius (2015b).

Figure 7: Appropriate and planned locations of wind parks in Slovenia



Adapted from Bordjan, Jančar & Mihelič (2012) and Aquarius (2015b).

In the studies presented above, only relatively big wind power stations on suitable locations were considered; smaller wind power plants have some potential as well, even though they are generally not appropriate for bigger institutional investors, which means that energy democracy and community projects, explained in subchapter 4.1 on solar energy, could play a role (Pollin, 2012; Bolinger, 2001; Bolinger, 2005). Since local inhabitants do have a stake in such investments, community wind projects are frequently located close(r) to communities and the electricity network, and farther away from nature. Their small size also makes it easier to connect them to the grid. I assumed that 10–15 mostly locally owned wind power stations could be set up by 2035, with overall installed capacity of approximately 30 MW and 50 GWh of electricity.

To conclude, I presume that ten wind parks with an installed capacity of 283 MW and smaller 10–15 wind power stations with 30 MW will be built by 2035; in total, that translates into 313 MW of wind power plant capacity generating 522 GWh of electricity. Moreover, adjusting for the slow pace of siting procedures, works would commence in 2023 and 180 MW and 313 MW of wind power plant capacity would be constructed by 2030 and 2035, respectively. The suggested progress would be slightly higher as in the NECP by 2035, after which the NECP suggests that new wind parks be built (2020, p. 143), whereas I believe that environmentally, socially, technically and economically sensible wind power potential will already have been exploited at that point.

If I consider the data presented above and the transfer capacity of a single 20 kV, which is roughly 8–10 MW, my calculations show that 52 MW of wind power station capacity could be connected to the distribution network and 261 MW to 110 kV lines (transmission network). Table 20 provides a summary.

Table 20: Wind power stations connected to transmission and distribution network in the 2022–2040 period

WIND POWER	2022	2025	2030	2035	2040
CAPACITY ON DN (MW)	3	13	30	52	52
GENERATION ON DN (GWh)	5	22	50	86	86
CAPACITY ON TN (MW)	0	56	150	261	261
GENERATION ON TN (GWh)	0	94	250	435	435
TOTAL CAPACITY (MW)	3	69	180	313	313
TOTAL GENERATION (GWh)	5	116	300	521	521

Source: own work baased on Bordjan, Jančar & Mihelič (2012) and Aquarius (2015b).

In addition to all the factors that support the feasibility of the proposed wind power plan, such a plan would also make it possible to avoid most conflicts with local communities and nature conservation groups. In doing so, it would build a broad consensus in society and consequently accelerate the green transition. Unregulated and uncontrolled siting of wind parks, guided by narrow profit interests, has been detrimental with long-lasting effects. The stark abyss between environmentally and socially suitable locations and privately proposed wind parks can be best seen from the map in Figure 7, where black areas mark appropriate locations, identified by Aquarius and DOPPS, whereas pink ones indicate privately proposed projects that have not been realized (yet). Unfortunately, most wind power projects have been intended to be built in areas where they would negatively impact nearby residents and nature. As experiences from Volovja Rebra, a territory well outside the appropriate areas (Figure 7), show, when wind turbines are installed in ecologically sensitive areas or near settlements, they face expected and justified opposition and anger from nature conservationists and local communities, which either delays the project or brings it to a halt. What is even more troublesome, such problematic investments – as Slovenia's own experience has shown – have enduring ramifications. They contribute to frequently unfounded, *a priori* and widespread opposition against wind power plants. Five years after the study was completed, the results are stark and grim. Only two wind turbines have been built in Slovenia, further emphasising the fact that the state should play a larger role in coordinating and stimulating the deployment of wind power plants under the plan above.

Considering the capital costs given in the NECP (Vlada Republike Slovenije, 2020, p. 128) and applying the equation (2), cumulative investments in wind power stations with a total installed capacity of 313 MW would amount to EUR 300.5 M by 2035 (Table 21).

Table 21: Annual and total investments costs of wind power stations in the 2022–2040 period (EUR M)

WIND POWER	2022	2023	2030	2031	2035	2022–35
INVESTMENT COSTS (EUR M)	0.0	21.8	21.4	25.7	25.4	300.5

Source: own work based on Vlada Republike Slovenije (2020).

4.3 Hydropower

4.3.1 Hydropower stations and their technical, economic, social, climate and nature conservation perspectives

There are 22 big hydropower plants (HPP) with a capacity above 10 MW (Vončina et al., 2020, p. 256) and more than 600 water rights have been granted for small hydropower plants (sHPP) with a capacity below 10 MW (Aquarius, 2015a, p. 4). Hydropower stations have played a significant role in Slovenia's electric power system. Not only do they provide roughly 40% of total domestic electricity, but their load-following generation profile, provision of various ancillary services, considerable production during the colder months and their storage potential also ensure security and reliability of supply. Half of the technical potential and roughly 60% of the economic potential have been already used (Kryžanowski & Rosina, 2012), which is a disproportionately high percentage compared to other low-carbon energy sources. HPPs also play an important role from the macroeconomic perspective, as approximately 90% of materials, equipment and services are sourced within Slovenia, generating an important multiplier effect (HSE, GEN energija & Savske elektrarne Ljubljana, 2012). In 2010, they contributed approximately 0.25% to GDP, and they also create a significant amount of short-term jobs during the construction period (Malovrh, 2019). However, long-term jobs are insignificant because the operation of the plant is highly digitalised. For example, the first three HPPs on the middle Sava would generate only 12 long-term jobs (Trotovšek, 2020, p. 23), which could possibly be (even) located outside of Zasavje region. HPPs provide low-carbon electricity but generate significantly more GHG emissions per unit of electricity than solar, wind or nuclear energy – 34 million tonnes of CO_2-eq./GWh over the lifecycle of the hydropower plant compared to 5, 4 and 3 million tonnes of CO_2-eq./GWh for solar, wind and nuclear power stations, respectively (Ritchie, 2020). Furthermore, the electricity generation potential of additional HPPs in Slovenia is relatively meagre. HPP Mokrice could cover approximately 1% of Slovenian electricity (Hidroelektrarne na spodnji Savi, 2019), and a few extra HPPs on the middle Sava, which could be constructed by approximately 2040 when the electric power system should be fully decarbonised, could guarantee a few extra % of total existing electricity generation (GEN skupina, n. d.). Since new HPPs would be of the run-of-the-river-reservoir type, flexibility capacities would be relatively insignificant. Additionally, alternatives (DSM, UPSHPP, etc.) exist that would cause less harm to nature. The future of the aforementioned and other HPPs is uncertain because nature conservation, social and legal hurdles (more on this in the following part) prolong and delay their construction and subsequently reduce their potential role in the future decarbonisation of the Slovenian electric power system. The authors of the Strategic Environmental Impact Assessment of the National Energy and Climate Plan (Vončina et al., 2020, p. 262) raised the same warning:

*"*The construction of individual hydropower stations on the middle Sava will only be possible if other public interests prevail over the public interest of nature conservation, which will be implemented at more detailed planning levels (national spatial plan, municipal spatial plan and procedures within the assessment of the strategic environmental impact and the environmental impact) and with the prior or simultaneous implementation of effective compensatory measures. As the procedures by which another public interest could prevail will be lengthy and their results questionable, we suggest that all NECP scenarios consider the fact that it may be unrealistic to count on additional electricity from HPPs on the middle Sava by 2030."

Hydropower stations could help tackle climate change by generating low-carbon electricity, but global warming also negatively affects them, additionally narrowing their potential future role in decarbonisation. In the words of the authors mentioned above (Vončina et al., 2020, p. 21):

*"*The rise in summer temperatures has also led to a rise in the evaporation rate across the country and to more frequent and extreme droughts. Spring and summer precipitation decreased by 10–15% and snow depth decreased by roughly 55% despite an increase in winter rainfall. Mean river flows have been diminishing since the 1960s … [T]he largest decline in mean river flows has been observed during the spring and summer because there was less snow cover and less rainfall during these seasons.*"*

Such developments are presumably one of the factors behind the fall in the 15-year average operating hours of HPPs, which have decreased from 4,225 hours in 2005 to 3,893 hours in 2018 or, in other words, by almost 8% in 13 years (Agencija za energijo, 2020, 32). And even though electricity generation from HPPs increased by nearly 10% during that same period, their installed capacities rose by approximately 19% (Agencija za energijo, 2020, 32).

On top of all that, hydropower stations have a negative impact on nature, biodiversity, climate and the local people. Considering the median values of plotted energy sources in Figure 2, HPPs cause the greatest damage to the ecosystem in each of the five parameters. Reservoir water surfaces are sources of greenhouse gas emissions due to the anaerobic decomposition of sludge and slime (Deemer et al., 2016). The loss of riverine vegetation (e.g. inundated forests and marshes), driven by the regulation of riverbeds and riverbanks to better manage and control the streamflow for HPPs, reduces carbon sinks (Mccartney, Sullivan, & Acreman, 2001), removes natural barriers against floods (Kingsford, 2001) and destroys the natural habitat of many animals and plants (Bunn & Arthington, 2002). Since HPPs disrupt the natural interchange between surface and underground flows, groundwater levels change, mostly decrease. Such adverse effects have been observed in the cases of HPP Zlatoličje (Žlebnik, 1982) and HPP Mavčice (Agencija Republike Slovenije za okolje, 2014). Silt that accumulates because of the dams covers the pores between boulders (interstitial zone), which is harmful for the microorganisms essential for water purification (Mori, Debeljak, Zagmajster, Fišer, & Branclej, 2020). As they damage wild rivers with a lively flow and abundant biodiversity, HPPs can also reduce the touristic potential of green destinations and thereby negatively affect the local economies. Slovenian tourism does not promote dams, but vivacious rivers and pristine nature (Slovenska turistična agencija, n. d.). Dams break up what was once an interconnected ecosystem into smaller parts, constraining migration and thus the viability of various populations (e.g. fish passages are 40% efficient (Noonan, Grant & Jackson, 2011)). Reservoirs slow down the river flow, causing an increase in water temperature and a loss of oxygen, due to which the river ecosystem becomes more similar to a lake habitat (Bunn & Arthington, 2002). Last but not least, regulation of riverbeds and riverbanks for a better management of water flow through turbines have three important consequences. First, they increase the severity of floods as they disconnect the river from natural floodplains and clear the riverbank of marshes and other vegetation, acting as a natural sponge (Trobec, 2011). Second, they exacerbate downstream inundations as they accelerate the streamflow (Trobec, 2011). Third, nature-friendly flood prevention measures that, for example, restore natural floodplains, meanders, marshes, flooded woods and other vegetation, can prevent floods, rewild ecosystems and store additional carbon (Besednjak & Ilc, 2008, pp. 10–16; Vovk Korže & Vrhovšek, 2007; Lallemant et al., 2021). Additionally, there is no sensible reason why flood prevention measures could not be implemented independently of the construction of hydropower plants.

These effects on nature and people's lives coupled with the fact that a significant part of the hydropower potential has already been exploited have caused a gradual decline in public support for HPPs in Slovenia (Hočevar, 2020). A similar shift is also taking place in the EU and Slovenian legislation.

On the EU level, three laws or legal principles are important in this respect. First we have the EU Biodiversity Strategy for 2030, under which at least 25,000 km of European waterways are to be renaturalised into free-flowing rivers (European Commission, 2020, p. 23). Second, the "do no significant harm" principle, included in the Recovery and Resilience Facility Regulation (European Commission, 2021b) and the forthcoming EU Taxonomy (EU Technical Expert Group on Sustainable Finance, 2020), significantly limits the use of these financial mechanisms for the construction of HPPs. Third, under Article 101 of the Nature Conservation Act (1999), which incorporated the framework of Natura 2000 into the Slovenian legal structure, the procedure of the prevalence of one public interest over public interest of preserving nature should be carried out if an object with significant negative impacts on nature is to be constructed. A damaging object can be built if a project serves a different public interest (e.g. public interest of electricity generation), if detailed compensatory measures are put in place and if "there are no other appropriate alternatives to fulfil [such] public interest".

4.3.2 New big HPPs with a capacity above 10 MW

Before I make a final decision on the future of big HPPs with a capacity above 10 MW in Slovenia, I should examine two additional national developments.

The first development is that the Strategic Environmental Impact Assessment of the National Energy and Climate Plan ascertained that the proposed HPPs on the Sava river would have significant negative impacts on nature and biodiversity (Vončina et al., 2020, p. XX). If the HPPs on the Sava river were included in the final version of NECP, the plan would not reach the environmental goals of sustainable management of natural resources and conservation of nature, more precisely the subgoals of a good state of surface waters, conserved biodiversity and preserved areas with nature conservation status. In such a case, the plan would obtain mark D (meaning that it has a significant negative impact), which would make it inappropriate for further procedure and would need to be shelved. The authors of the impact assessment (Vončina et al., 2020, pp. XX–XXII) thus proposed forgoing investments in hydropower plants on the Sava river. The document would obtain mark C (meaning that its impacts are insignificant if compensatory and mitigation measures are implemented), which would mean that the NECP could be published. To offset a lower generation of low-carbon electricity and thus make refraining from new HPPs justifiable, the authors of the strategic assessment proposed to reduce final energy demand by deepening the energy efficiency measures and increase the threshold for allowed imports (Vončina et al., 2020, pp. XX–XXII). In the end, construction of big HPPs was included in the text without detailed locations (i.e. no mention of HPPs on the Sava river), only after 2030 (i.e. beyond the time frame of the document) and with a clear diction that their construction should be in line with the legislation (i.e. for Natura 2000 sites, it hinges on the prevalence of public interest of electricity generation over the public interest of nature conservation). The decisions on this matter, precedent is currently unfolding in the case of HPP Mokrice, are yet to be seen.

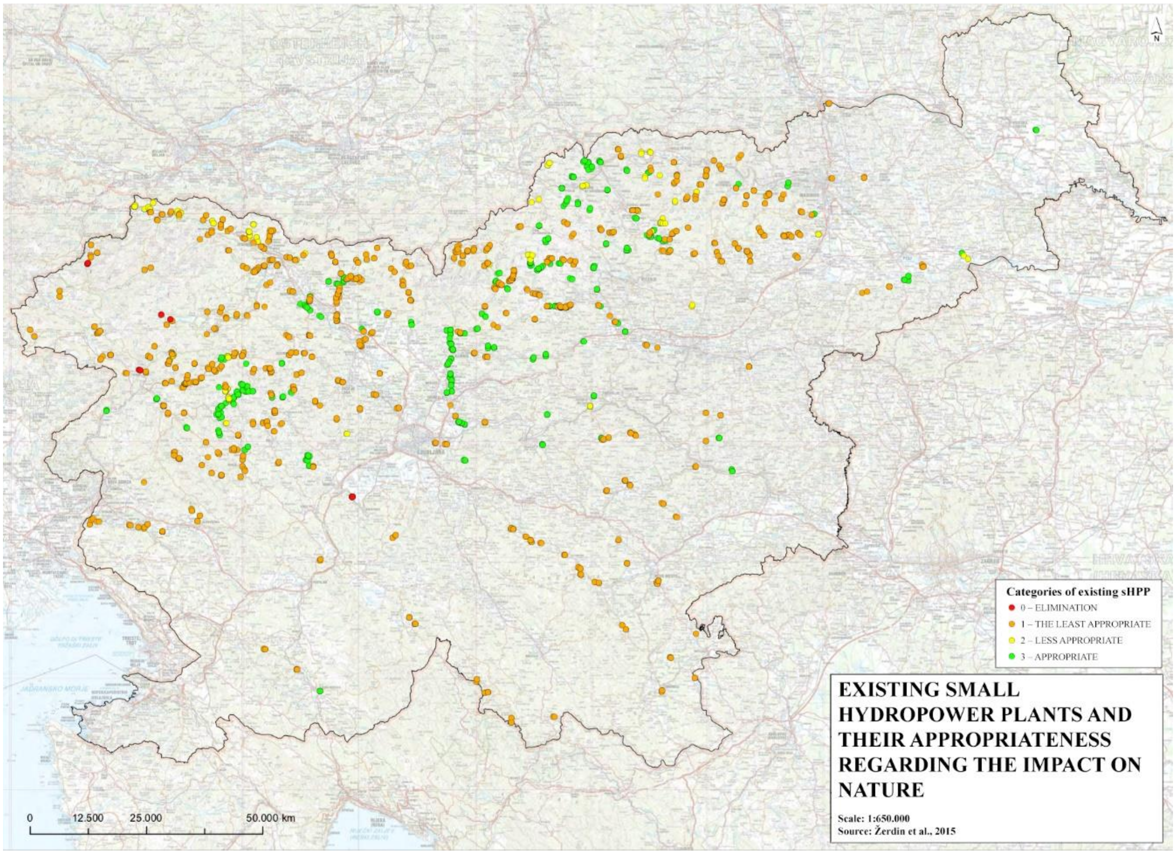
The second development pertains to the planned HPP Mokrice, which has been the subject of the above-mentioned legal case regarding the prevalence of public interest of low-carbon electricity production over the public interest of nature conservation (Konečnik, 2021). For the public interest of electricity generation to prevail, the proponents of HPP Mokrice should demonstrate that no other appropriate solutions for fulfilling such public interest exist and that compensatory and mitigation measures can alleviate the devastating impact on the nature. *Vice versa*, opponents should prove that less destructive technologies do exist which could generate approximately 131 GWh of electricity per year (i.e. as HPP Mokrice is expected to produce) or that the electricity demand could be brought down for that same amount. The case has not been settled yet, but it marks a precedential trial influencing the future interplay between energy development and nature conservation in Slovenia. As the legal proceeding itself demonstrates, litigation juxtaposes two imperatives – nature conservation and decarbonisation efforts. Herein lies the root problem: these two goals should not be mutually exclusive under my five-pillar approach.

Considering the figures shown in this subchapter, the sensible decarbonisation plan presented throughout the master's thesis and my biodiversity pillar, I deem that new HPPs are unnecessary for successful decarbonisation and in contradiction to my five-pillar scheme. Therefore, I do not propose new big HPPs in my program. Moreover, HPPs contribute to GDP and provide some critical services to the electric power system. However, they do not add to green growth and are not part of sustainable development as "balance [between] social, economic and environmental sustainability" is not met (United Nations, n. d.).

4.3.3 New small HPPs with a capacity below 10 MW

More than 600 water rights have been granted to small hydropower plants (sHPPs) with a capacity below 10 MW in Slovenia (Aquarius, 2015a, p. 4). Their total installed capacity was 155 MW and they generated 383 GWh of electricity in 2017 (Vlada Republike Slovenije, 2020, p. 144). Their impact on nature is similarly detrimental as the impact of big HPPs, only on a smaller scale (Vončina et al., 2020, pp. 238, 259). Still, it can also be much worse than that because, first, there is little to no oversight; second, the operators are frequently non-institutional actors who care little for their power plant, and, lastly, since sHPPs along one river are often operated by many companies separately, individual actions of various actors can cumulatively bring about greater adverse effects than numerous activities by one player (as is the case for big HPPs) (Vončina et al., 2020 pp. 238, 259). Similarly to the above-mentioned study on the wind power potential in Slovenia, Žerdin and co-authors (Aquarius, 2015a) assessed the impacts that existing and projected sHPPs would have on nature and proposed guiding principles on siting sHPPs without causing significant damage to the natural world. The authors assigned each sHPP location into one of four categories: appropriate location, which means that the power plant is sited in an area not identified as essential for aquatic and riparian organisms; less appropriate area, which indicates the power station is situated in a locality of great importance for rare, endangered and protected species; the least appropriate site, which means that the power plant is located in an area highly vital to aquatic and riparian habitats and related species and that there is a high risk of the construction negatively affecting the characteristics of natural values as defined by the law. The last, fourth category is a prohibited zone, signifying that it should be illegal to construct sHPPs on such locations. The results (Aquarius, 2015a, p. 28) show that 27% of the existing sHPPs are located on appropriate locations, 8% in less appropriate areas, 64% on the least appropriate sites and 1% in prohibited zones. The exact sites are presented in the Figure 8, taken from the study conducted by Aquarius (2015a).

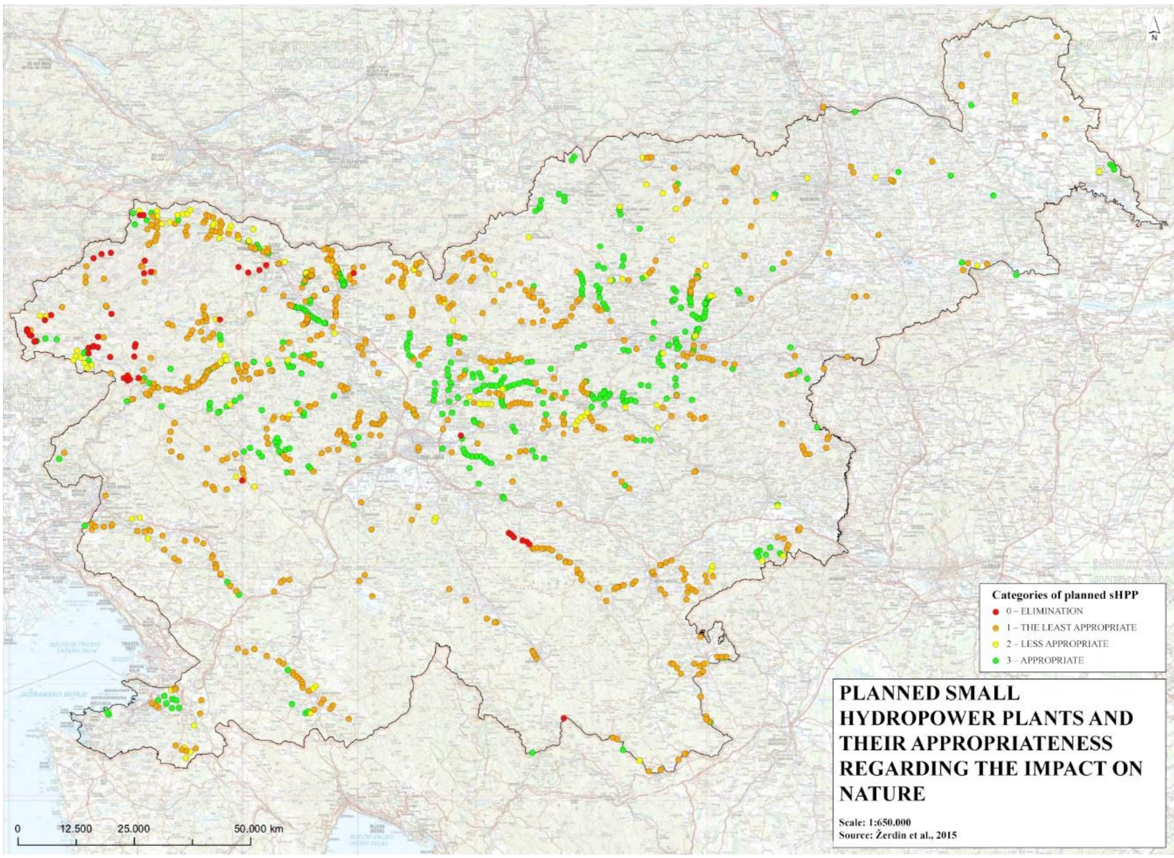
Figure 8: Existing small hydropower plants and their appropriateness regarding the impact on nature



Adapted from Aquarius (2015a).

When assessing the impact that planned sHPPs could have, Žerdin and co-authors (Aquarius, 2015a) obtained similar results – 34% of potential locations for sHPPs were appropriate, 10% less suitable, 55% the least appropriate and 4% fell within prohibited areas. The map (Figure 9), taken from the same study (2015a), shows the exact locations and impact of proposed sHPPs on biodiversity and ecosystems.

Figure 9: Planned small hydropower plants and their appropriateness regarding the impact on nature



Adapted from Aquarius (2015a).

In light of the Aquarius study, the authors of the NECP have proposed to modernise and revitalise the existing sHPPs and site new plants at locations where unused or partly used barriers and dams already exist and where the effects on nature would be insignificant (Vlada Republike Slovenije, 2020, p. 144). In this case, the currently installed capacities of 155 MW would increase only slightly, i.e. to 159 MW and 177 MW in 2030 and 2040, respectively (Vlada Republike Slovenije, 2020, p. 144). I use the same rate of deployment also in my plan. Moreover, since more than two thirds of the existing sHPPs are sited in less and the least appropriate or prohibited areas, I propose that the least productive and oldest sHPPs the size of 22 MW be removed and decommissioned, which means that the net installed capacity would be left unchanged (i.e. 155 MW). In the last few years, dam removals have been gaining ground in Europe and United States due to their beneficial effects on tourism (Getzner, 2014), local development (Headwaters Economics, 2016) and nature (Birnie-Gauvin, Larsen, Nielsen & Aarestrup, 2017). Such actions are also driven by safety concerns (Adamo, Al-Ansari, Sissiakian, Laue & Knutsson, 2020), green jobs (Nielson-Pincus & Moseley, 2010) and economic reasoning, according to which it can be less costly to remove dams than to maintain them and set up expensive obligatory fish passages (Gradowski, Chang & Granek, 2018). Last but not least, legal requirements underpin the sensibility of dam removals. EU Biodiversity Strategy for 2030 prescribes the renaturalisation of at least 25,000 km of European waterways into free-flowing rivers (European Commission, 2020, p. 23). To conclude, I propose revitalising or constructing sHPPs with an installed capacity of 22 MW by 2040 in the areas identified in Figures 8 and 9 (green dots) and simultaneously decommissioning the same size of the oldest, most damaging and least productive sHPPs. Total installed capacity would thus remain unchanged.

Considering the investment costs presented in the NECP (Vlada Republike Slovenije, 2020, p. 128) and using equation (2), revitalising or constructing 22 MW of sHPPs by 2040 would amount to EUR 57.2M. Table 22 provides the overview. The costs of removing dams and decommissioning sHPPs have not been included in the decarbonisation plan.

Table 22: Small hydropower plants in the 2022–2040 period: new installed capacities, investment costs and total costs

SMALL HYDROPOWER PLANTS 2022–2040	
NEW INSTALLED CAPACITY (MW)	22
TOTAL INSTALLED CAPACITY (MW)	155
INVESTMENT COSTS (EUR/kW)	2,600
TOTAL COSTS (EUR M)	57.2

Source: own work based on Vlada Republike Slovenije (2020).

4.4 Heating sector and its implications for electric power system

Since different systems and sectors are becoming more and more intertwined, a sensibly managed and developed heating sector could contribute to a more reliable and secure electricity supply in the future. Based on conversations with various local and national experts, I have identified three main paths that the part of the heating sector intertwined with the electric power system can take: power-to-heat technologies (heat pumps, electric boilers), installations running on biomass (CHP plants) and power plants using some form of gas as an energy source (CHP stations). The fourth option is to set up thermal solar panels, operating mostly during the warmer months, and underground thermal energy storage or pit storage for seasonal storage (International Renewable Energy Agency, 2019, pp. 10–11). Such an option seems plausible, but it is not considered due to excessive costliness (Tavčar, 2021).

4.4.1 Power-to-heat technologies

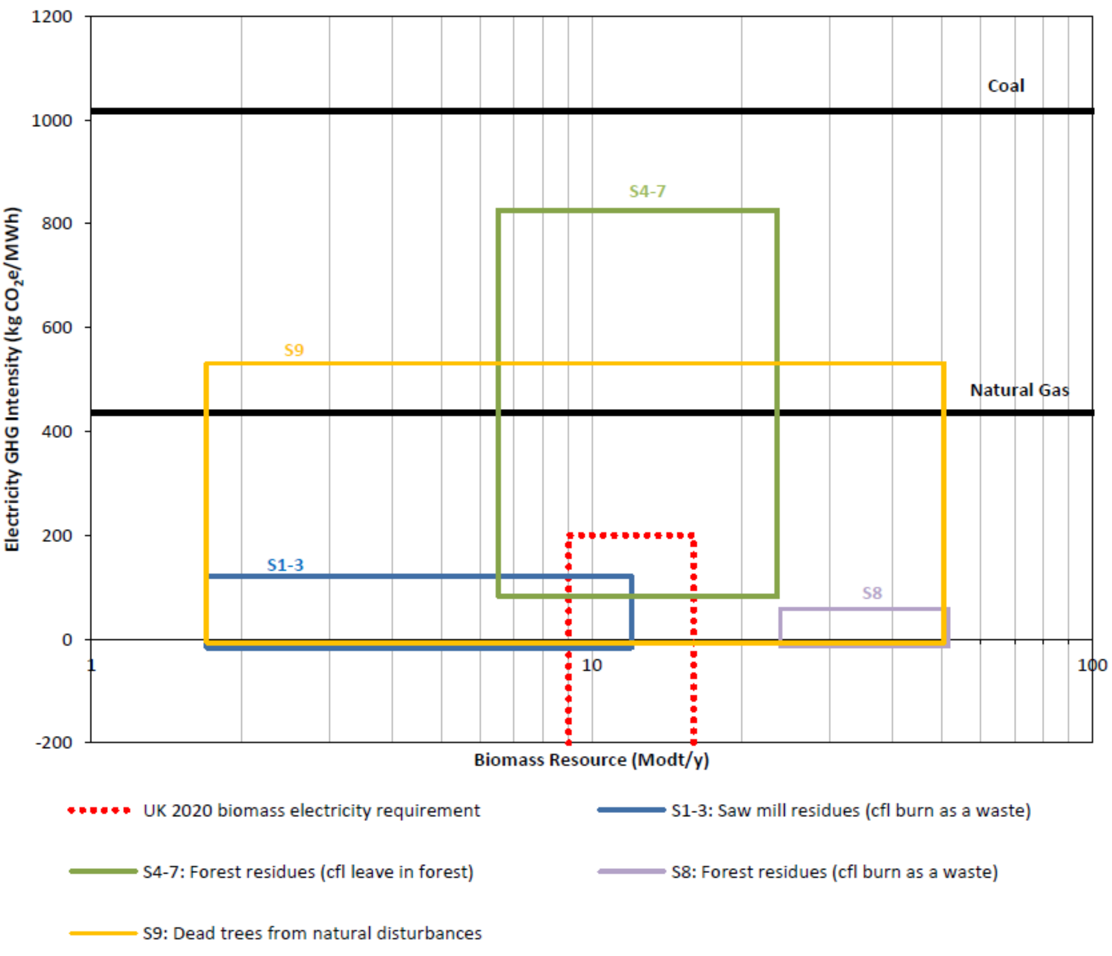
When power-to-heat technologies (e.g. heat pumps, electric boilers) are accompanied by low-carbon electricity, they can significantly contribute to the decarbonisation efforts and provide various beneficial services to the system (e.g. load shifting, demand-side management, peak shaving and valley filling), especially if combined with thermal energy storage. Such services can be provided by the consumer itself or via an aggregator. These installations make it possible to couple the electricity and heat sectors and thereby reduce the summer curtailment of SPPs and enhance the flexibility of the system (International Renewable Energy Agency, 2019). In the summer, when production of solar power stations is high, the heating sector could use the surplus in an efficient and cost-effective manner. Cost reductions due to power-to-heat technologies are driven by "the substitution of fossil fuels, better use of capital invested in renewable assets by means of reduced curtailment, less need for costly ancillary technologies such as peak-load capacity or power storage, more efficient operation of thermal power plants because of less need for cycling and part-load operation and the use of existing district heating infrastructure" (Bloess, Schill & Zerrahn, 2018, p. 1620). Whereas the efficiency of an electric boiler is 100%, heat pumps can operate at a much higher coefficient of performance under the right conditions (e.g. high surrounding temperatures). This option is even more attractive if cheap electricity from, for example, a solar power plant could be used. However, the optimal conditions for power-to-heat technologies all but disappear in the winter, which is a time of peak demand, low generation from SPPs and low temperatures. Coefficient of performance can fall below two, demand reaches its annual peak, also driven by power-to-heat technologies, and supply decreases, especially in variable RES-dependent systems. The problem is aggravated since outside temperatures highly determine the coincidence factor of heat demand. When temperatures are low, heat demand rises, pushing electricity demand up. If heat pumps and electric boilers are used, the coincidence factor is near one (Sistemski operater distribucijskega omrežja, 2020, p. 130), causing a significant load upsurge in a short period of time. Nowadays, the system is set up to cover a peak load of 1 kW per customer. This value can be brought up to 10 kW per customer with heat pumps, inducing adverse effects on the electric power system (Sistemski operater distribucijskega omrežja, 2020, p. 130). What is more, wind power plants, which generally generate more electricity during the colder months, cannot mitigate such situation because wind power potential in Slovenia is limited (see subchapter 4.2 on WPPs). Since the EU has been phasing out coal and, in some countries, nuclear power, it is likely that imports during the period of peak demand will become more uncertain and expensive. In addition, sensible and game-changing seasonal storage options, by which excess (solar) generation by specific energy carriers can be stored for the winter months, are still technologically and/or economically unviable on a large scale. Thus, from a system-wide perspective, an uncontrolled expansion of power-to-heat technologies without a substantial increase in new power stations, ancillary services, strategic reserves, smart grids and storage facilities is not an option. For example, if the heating sector were electrified to a large extent, peak load would be as high as 5,000 MW (correspondence with ELES employee). It is unrealistic that such a load could be covered within the next two or three decades. Therefore, as I have already proposed for the Šaleška valley, climate-friendly heat pumps and boilers can and should play a future decarbonisation role, but mostly in the warmer months. Since they can be detrimental to the system during the colder parts of the year, their deployment needs to be planned and regulated, and mitigation measures (e.g. construction of adequate capacities of CHP plants, CCGTs and OCGTs) should be implemented.

4.4.2 Unsustainability of biomass and CHP stations using natural gas, hydrogen, synthetic natural gas and alternative sources

Concerning the part of the heating sector related to the electric power system and taking into account mostly colder months, there are two sensible options left: CHP plants using either biomass (Tavčar, 2021) or natural gas (Mervar, 2021). Both energy sources can be used in all weather conditions and they generate more electricity and heat in the colder months when the supply is limited and more expensive. There are at least eight arguments why natural gas is perceived as superior to biomass.

First, many types of wood generate a similar or larger quantity of carbon emissions than natural gas per unit of electricity generated (Stephenson & MacKay, 2014; Camia et al., 2021). A study prepared by two renowned scientists from the University of Cambridge for the Department of Energy and Climate Change of United Kingdom found that this holds true for all types of roundwood and half of the woody residue types (Stephenson & MacKay, 2014, pp. 7, 12). As can be seen from the Figure 10, taken from that same study (Stephenson & MacKay, 2014, p. 7), only forest residues, which are otherwise burnt on the roadside, and saw mill residues, usually burnt as waste, have a lower carbon intensity than natural gas per unit of electricity. Forest residues and trees that die due to natural disturbances, which are normally left in the forest to slowly decompose, can have a lower, similar or higher carbon intensity than natural gas, depending on wood's origin and context. These are the results for a time frame of 40 years. Since trees are, in absolute terms, more carbon-intensive than black coal and emit more carbon per unit of energy than black coal (Partnership for Policy Integrity, 2011, p. 1), biomass would perform much worse in a shorter timeframe (i.e. less time for the forest to regrow and steadily sequester previously emitted carbon dioxide). And precisely the latter is the case - it is most urgent to act now and not wait a few decades. Camia et al. (2021) came to similar conclusions in a study published by EC's Joint Research Centre.

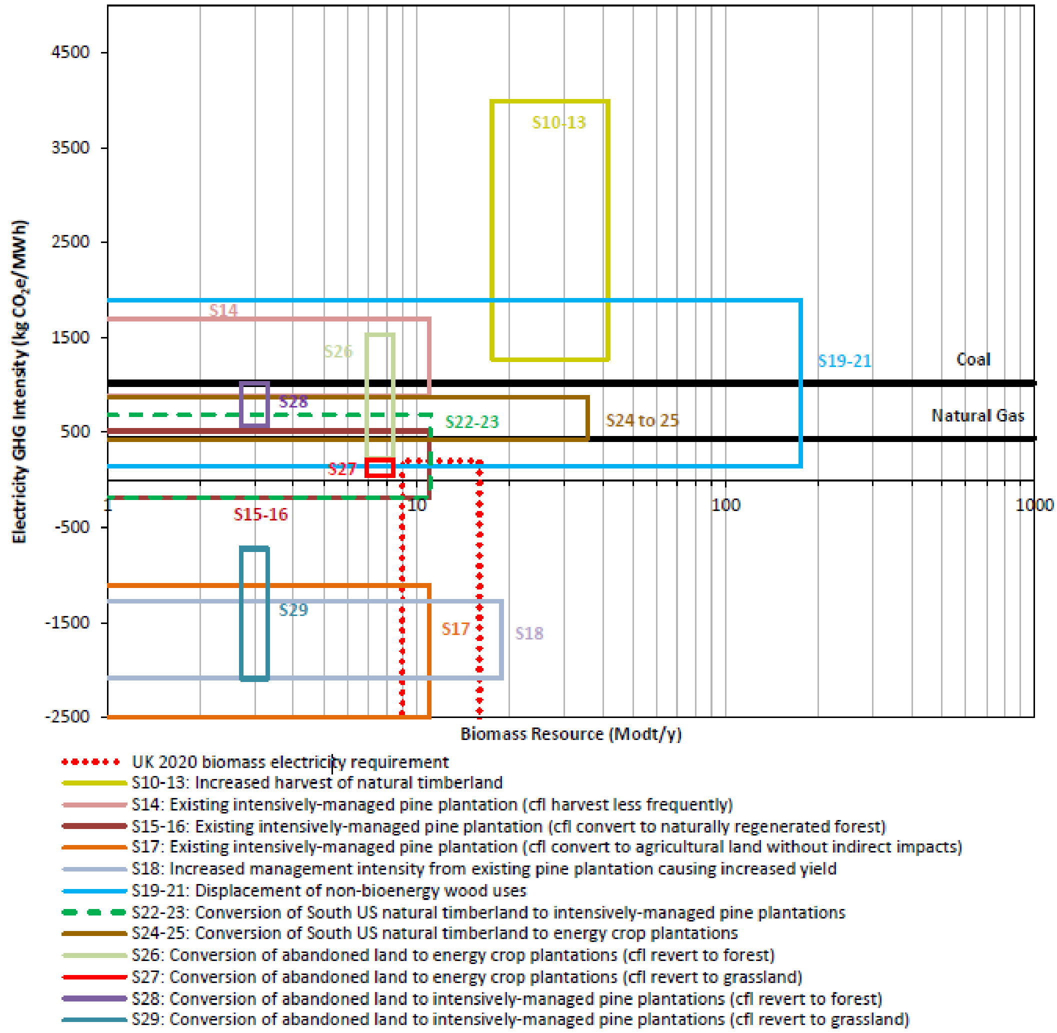
Figure 10: Various woody residues and their GHG intensity over 40 years (kg CO_2-eq./MWh)



Source: Stephenson & MacKay (2014).

If forest residues are roughly similar to natural gas in terms of carbon per unit of electricity, the results for various logged roundwood types are even more unfavourable (Stephenson & MacKay, 2014, p. 12). Considering increased harvest of natural timberland scenario (S10-13 in Figure 11) and displacement of non-bioenergy wood uses scenario (S19-21 in Figure 11), which both resemble the Slovenian existing policy proposals (Vlada Republike Slovenije, n. d.), these types of logged roundwood are in almost all cases worse than natural gas and in most circumstances even than coal (Figure 11). Additionally, as natural gas can be blended with hydrogen and synthetic natural gas and as both of these are to be injected into the gas pipeline network from 2025 onwards, the carbon intensity of natural gas should gradually decrease.

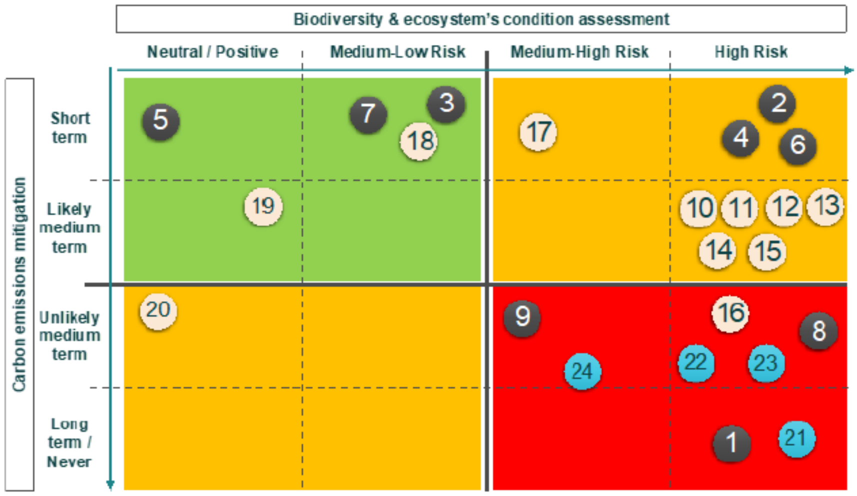
Figure 11: Various roundwood and energy crops and their GHG intensity over 40 years (kg CO_2-eq./MWh)



Source: Stephenson & MacKay (2014).

The second argument against biomass vis-à-vis natural gas relates to nature conservation. Camia et al. (2021, p. 9) devised three broad biomass pathways with 24 specific scenarios and assessed their impact on biodiversity, ecosystems and carbon emissions. As the logging residues removals pathway is the only one applicable to the Slovenian biomass strategy (Vlada Republike Slovenije, n. d.), only the scenarios that fall under this pathway should be considered. As shown in Figure 12, taken from Camia et al. (2021, p. 9), only one of them has a neutral or positive effect on biodiversity and ecosystems. Two carry low to medium risk, while the remaining six fall into the category of high risk, which further underlines the incompatibility between conserving and restoring biodiversity on the one hand and using biomass on the other. Furthermore, Camia et al. (2021) do not estimate the impacts of using directly logged roundwood (not residues) on biodiversity and ecosystems, which would make the results even more appalling. These results have been confirmed by numerous reports and studies (e.g. Beddington et al., 2018; FERN, 2021).

Figure 12: Various biomass pathways and their impact on biodiversity, ecosystems and carbon emissions



	ID	Pathway description
Logging residues removals	1	Coarse Woody Debris removal
	2	Fine Woody Debris (Slash + foliage/needles) removal above landscape threshold
	3	Fine Woody Debris (Slash + foliage/needles) removal below landscape threshold
	4	Fine Woody Debris (Slash - Coniferous) removal above landscape threshold
	5	Fine Woody Debris (Slash - Coniferous) removal below landscape threshold
	6	Fine Woody Debris (Slash - Deciduous) removal above landscape threshold
	7	Fine Woody Debris (Slash - Deciduous) removal below landscape threshold
	8	Low stumps removal above landscape threshold
	9	Low stumps removal below landscape threshold
Afforestation	10	Natural grassland afforestation with monoculture plantation
	11	Natural grassland afforestation with polyculture plantation
	12	Natural grassland afforestation with other planted forest
	13	Anthropogenic heathland afforestation with monoculture plantation
	14	Anthropogenic heathland afforestation with polyculture plantation
	15	Anthropogenic heathland afforestation with other planted forest
	16	Natural forest expansion on anthropogenic heathland
	17	Former agricultural land afforestation with monoculture plantation
	18	Former agricultural land afforestation with polyculture plantation
	19	Former agricultural land afforestation with other planted land managed with low intensity
	20	Natural forest expansion on former agricultural land
Conversion to plantation	21	Conversion of primary, old-growth forest, to plantation
	22	Conversion of native naturally regenerating forest to monoculture plantation
	23	Conversion of native naturally regenerating forest to polyculture plantation
	24	Conversion of native naturally regenerating forest to other planted forest managed with low intensity

Source: Camia et al. (2021).

The third argument is also related to the climate, more precisely to carbon sequestration. Forests are, along with oceans, the most crucial carbon sink in the world and their natural ability to store CO_2 makes them quintessential for combating climate change. Therefore, the Resolution on the Slovenia's Long-Term Climate Strategy By 2050 rightly recognises the essential role of nature conservation, including forest conservation, in climate change mitigation (Državni zbor Republike Slovenije, 2019, pp. 11–14). In the last few years, Slovenia has seen a series of detrimental events intensified by climate change due to which forests have been a net source (not sink) of GHG emissions. In other words, the release of carbon into the atmosphere has been greater than its sequestration (Državni zbor Republike Slovenije, 2019, p. 59). Aforementioned resolution envisions that forests will once again become a net carbon sink in the following years (Državni zbor Republike Slovenije, pp. 60–61). Such a shift demands changes in how we manage forests and implement conservation practices. It seems quite likely that some activities for obtaining the biomass needed for energy and heat purposes will contradict climate-related conservation requirements.

The fourth argument is related to the energy input required to produce a unit of electricity. Compared to other energy sources, biomass requires significantly more energy per one unit of electricity generated to be prepared, transported and burned. Depending on the circumstances, some types of biomass can even reach EIR of 100%, meaning energy inputs are the same as energy outputs (Stephenson & MacKay, 2014, pp. 10, 18)

The fifth argument is that construction, manufacture of furniture and similar activities represent higher value-added sectors than the ones where wood is simply burned for electricity or heat (Vlada Republike Slovenije, n. d., p. 9). Consequently, the Resolution on the Slovenia's Long-Term Climate Strategy By 2050 (Državni zbor Republike Slovenije, 2021, p. 22) proposes cascading use of biomass, where burning wood comes only at the end of the cycle. If such policy is not respected, increased biomass consumption for electricity and heat generation will likely intensify the logging activities or/and preclude higher value-added activities from gaining access to biomass.

The sixth argument touches upon the levelized cost of electricity (LCOE) (i.e. a metric where all the costs and revenues are deducted to determine the average net present cost of electricity production for a generating plant over its lifetime (International Energy Agency & Nuclear Energy Agency, 2020, pp. 33–40)). Whereas LCOE of biomass-fired CHP plants ranged between 101 and 270 EUR/MWh in 2018, LCOE of gas-fired CHP stations was 85 EUR/MWh (European Commission, 2020e, p. 34).

The seventh argument deals with the health effects of using biomass to generate electricity and heat. Biomass burning is the biggest emitter of harmful particulate matter, namely PM2.5 and PM10, which have adverse effects on human health, in the EU and in Slovenia (DOPPS, 2021 pp. 1–2). In 2018, stoves that predominately burn wood for heat were responsible for 58% of all PM10 and 70% of all PM2.5 pollution in Slovenia (DOPPS, 2021, p. 2). This problem can be reduced by installing new and high-quality stoves with filters, shifting from individual to utility-scaled appliances, using well-prepared and sufficiently dry wood and, lastly, providing better supervision by inspectors and chimney sweeps. However, if biomass was used in high-quality, community- or utility-scaled CHP plants, the burning of biomass could generally become more acceptable, which would create a lack of supervision as the number of appliances would increase and leave more room for inappropriate use of fuels and devices. Promoting biomass burning for heat and electricity purposes could thus prolong the looming health crisis. Moreover, the real factor in reducing the amount of harmful particulate matter in the atmosphere would be downsizing biomass usage for heat and electricity purposes altogether.

The last, eighth argument touches upon the feasibility of the green transition, which would be easier to achieve with natural gas than biomass because hydrogen and synthetic natural gas can easily blend and, with some technical adjustments, replace natural gas in power plants.

The consequences of these eight arguments are already visible. First, Article 29 of the reformed EU Directive on the promotion of the use of energy from renewable sources states that energy from biomass fuels can contribute to the national renewable energy targets and biomass-fired power plants are eligible for financial support only if they meet sustainability and the greenhouse gas emissions saving criteria (Directive (EU) 2018/2001, pp. 48–52). In paragraph 10, GHG emissions saving criteria are defined as savings amounting to “at least 70% for electricity, heating and cooling production from biomass fuels used in installations starting operation from 1 January 2021 until 31 December 2025, and 80% for installations starting operation from 1 January 2026” compared to alternative energy-generating technologies. If the savings are smaller, a biomass-fired power station does not contribute to the renewable energy target and is not eligible for financial support. As shown in the first argument above, such strict criteria is hardly met by any type of wood when compared to natural gas. Second, when the National Strategy for Phasing Out Coal was being prepared, the biomass usage in the coal-fired unit 6 of TEŠ was proposed as a mitigation policy to extend the service life of unit 6. Due to similar objections from NGOs as listed above (Gobbo, Štros & Brecel, 2021, pp. 5–7), the Ministry of Infrastructure waived the idea and did not include it in the last version of the strategy.

To conclude, industrial wood residuals and 30% of forest residues from low-quality wood logging that otherwise slowly decompose in the forest are assumed to be climate- and biodiversity-friendly and thus appropriate for heat and electricity generation. The current supply of industrial residuals and 30% of forest remnants from low-quality wood logging amounts to 663 kilotonnes (kt) (Vlada Republike Slovenije, n. d., pp. 10–11), while the existing biomass consumption for energy and heat purposes is 902 kt. If we compare the two values, we can see that the current use surpasses the upper limit and does not enable an increase.

However, some would argue that another option is to use biomass currently burned by households in bigger CHP plants with higher efficiency, which would not require any additional logging. Even though this holds true in theory, logistical (how to economically organize the process of collecting the woods from dispersed households), environmental (collecting small quantities of wood from various dispersed households to assemble them in one place could spur a lot of fossil fuels-dependent transport) and social (people in rural places use biomass from their own forests because this heating option is free of charge, meaning that if biomass usage is diverted and these people are not adequately compensated, social distress could deepen) challenges exist. As I am not aware of any sensible projects that would address and resolve these issues and offer socially and environmentally friendly redirection of biomass usage, it seems sensible to stay on the safe side and abstain from any such actions.

To acquire installed capacities of CHP plants, values from NECP (Vlada Republike Slovenije, 2020, pp. 43–45, 150)[16] are increased as its capacity factors (0.58–0.67) seem too high. Based on the assumed capacity factor of roughly 0.45 (i.e. slightly higher than the past average capacity factor of CHP plants excluding Ljubljana), installed capacities of CHP stations, including the one in the Šaleška valley but not the one in Ljubljana, would increase to 293 MW by 2030 and 338 MW by 2040. These systems would, using equation (3), generate 1047 GWh and 1247 GWh of electricity by 2030 and 2040, respectively. I propose that the projected increase in CHP is covered mainly by gaseous energy sources (natural gas, hydrogen and SNG). From the existing 30% share of gaseous energy source (natural gas) in the CHP plants (Agencija za energijo, 2021, p. 251), hydrogen and SNG would supply 60% of primary energy by 2040 (including the CHP station in Ljubljana). The remaining part would be covered by RES (the consumption of biomass would remain unchanged, whereas the consumption of biogas would increase), industrial waste heat, waste (only once prevention, re-usage and recycling measures will have already been put in place) and other alternative sources.

Based on the average investment costs (EUR/kW) given in the NECP (Vlada Republike Slovenije, 2020, p. 128) and employing equation (2), total investment costs would amount to EUR 176M by 2030 and EUR 75M by 2040, excluding the costs for the CHP plant in the Šaleška valley, as it is included in the regional restructuring plan, and the CHP plant in Ljubljana. If I add the power station in Šaleška valley, the investments needed would reach EUR 260M by 2030 and EUR 75M by 2040. Table 23 summarizes the data.

Table 23: CHP stations (without TETOL) in the 2022–2040 period: installed capacities, electricity generation and investment costs

CHP STATION (w/o TETOL)	2020	2030	2040
INSTALLED CAPACITIES (MW)	138	293	338
GENERATION (GWh)	499	1,047	1,247
AVERAGE INV. COSTS (EUR/kW)	1,675		
TOTAL INV. COSTS (EUR M) (w/o Šaleška v.)		176	75
TOTAL INV. COSTS (EUR M) (w Šaleška v.)		260	75

Source: own work based on Vlada Republike Slovenije (2020).

4.5 (Underground) pumped storage hydropower plant

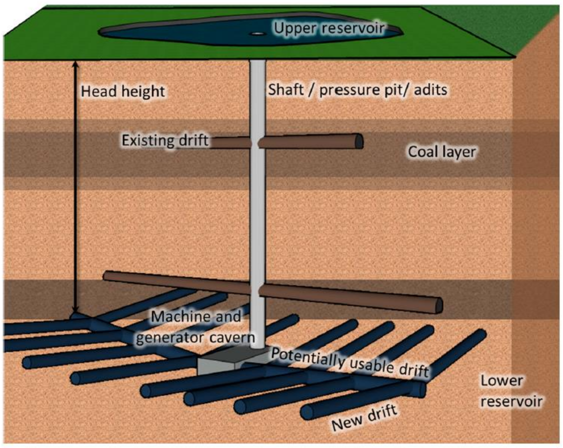
As the share of electricity from vRES is going to increase, so will the requirements for additional capacities of aFRR. The same will happen with the need for extra capacities of mFRR due to the construction of JEK2 on the one hand and energy storage in times of high production from vRES and electricity production in times of low generation from vRES on the other. Since peak/off-peak electricity price spreads depend on the variability and

[16] As the data is taken from the graph, some numbers might be inaccurate. The data does not include TETOL and TEŠ.

intermittency of future power plants, they will most likely broaden. One of the most promising, mature and well-developed technologies to cope with such challenges is the pumped storage hydropower plant. PSHPPs currently represent almost 99% of all the on-grid storage capacities (Menendéz at el. 2019, p. 1382). International Renewable Energy Agency predicts that their installed capacity could almost double by 2030 (in Menendéz at el. 2019, p. 1382). They store energy in times of high production and generate electricity in times of low production, exploiting high price spreads. Additionally, they contribute to supply reliability through ancillary services, especially aFRR and mFRR. Since PSHPPs are frequently located in sparsely populated, hilly or mountainous landscapes where exploiting vast differences in height between upper and lower reservoirs, there are usually many environmental obstacles (e.g. Natura 2000) regarding PSHPPs and new electric lines connecting distant PSHPPs with transmission networks. Projects are thus often delayed or abandoned. That has been the case with ČHE Kozjak in Slovenia, which was shelved in the 2010s due to, among other reasons, local opposition and conservation concerns (Červek & Rubin, 2011). In the last few years, DEM has started to revive the idea. The project's future is thus highly uncertain, or as ELES has put it (ELES, 2019, p. 84), "its realisation is less probable". Returning to the framework delineated in the initial part of the master's thesis, as a project that is less damaging and more socially acceptable, has similar characteristics and is also more sensible in terms of a just transition and from a legal point of view does exit, ČHE Kozjak has not been included in the decarbonisation plan. Alternatively, I propose an underground pumped storage hydropower plant Rudar within PV's mining structures.

Even though an underground pumped storage hydropower plant has never been built before, its concept and structure are similar to a regular PSHPP. Moreover, in the last years, interest in such power plants has risen worldwide (Madlener & Specht, 2020; Menéndez, Loredo, Galdo & Fernández-Oro, 2019; Menéndez, Loredo, Fernandez & Galdo, 2017; Montero, Wortberg, Binias & Niemann, 2016; Menéndez & Loredo, 2019; Niemann, 2018). The concept and structure, depicted in Figure 13, of such plants are similar to a regular PSHPP.

Figure: 13 Illustration of a UPSHPP with a rib-shaped design



Source: Madlener & Specht (2020).

The three existing lakes in Šaleška valley would be used as the upper reservoir. The existing and newly constructed horizontal tunnels and drifts starting in the lowest part of the deepest shaft would be operated as a lower reservoir. The Nove Preloge transport shaft, the deepest and main shaft for the transportation of miners and coal in PV, would be used as a penstock for carrying water up and down. The head height (i.e. vertical height between the upper reservoir and the turbine) is one of the most critical factors in the economic viability of such projects. The Nove Preloge shaft is 416 meters deep, which is sufficient, but not the best (Madlener & Specht, 2020, p. 9). The intention is to have UPSHPP with 225 MW of installed capacity and roughly 1,100 MWh of storage capacity. Such constellation would enable around 5 hours of operation at full load, which is less than the PSHPP Avče's (hereafter ČHE Avče) potential and at the lower bound of most existing PHPPs (Madlener & Specht, 2020, p. 9). However, as argued by Madlener and Specht (2020, p. 9), future energy markets with a considerable share of intermittent electricity generation from RES will require reserve energy capacities with smaller reservoirs, which would operate more frequently and for a shorter period of time, more than massive energy storage capacities, which would transfer excess electric production from the night to noon hours. If the UPSHPP's installed capacity is 225MW with approximately 415 m of head height and roughly 1,110 MWh of storage capacity, the lower reservoir's size will need to be one million m^3 (Menéndez, Loredo, Galdo & Fernández-Oro, 2019, p. 1384; Madlener & Specht, 2020, p. 9). The three lakes caused by mining in the Šaleška valley have more than 46 million m^3 of water (Mestna občina Velenje, n. d.), which guarantees the appropriateness of the upper reservoir. The cheapest option for constructing the lower reservoir would be to use the existing horizontal tunnels and drifts. However, since the excavation method used in Velenje causes the coal-rich ceilings above the drifts to collapse, most of the tunnels are filled up and, only in some instances, caverns and tunnels have been left behind (Premogovnik Velenje, n. d.). Such structures and strengthened and cladded drifts, currently used as the main horizontal transport routes for people and material, could be exploited and repurposed. Apart from them, new rib-shaped horizontal drifts are expected to be required. Therefore, I propose a lower reservoir, which would be comprised mostly of newly constructed horizontal tunnels and, to a much lesser degree, of existing structures. The length of the tunnels with a storage capacity of one million m^3 of water would be approximately 20 km (Madlener & Specht, 2020, p. 9). Additionally, turbine(s) and generator(s) would be sited in the existing or newly excavated caverns. The same holds for air conditioning shafts, used to lower the air pressure and ease the water flow into the tunnels during the generation regime. Table 24 provides a technical overview.

Table 24: Technical characteristics of PČHE Rudar

PČHE Rudar – technical characteristics	
Head height (m)	415
Lower reservoir (m^3)	1,000,000
Length of tunnels (km)	20
Storage capacity (MWh)	1,074

Source: own work based on Menéndez, Loredo, Galdo & Fernández-Oro (2019) and Madlener & Specht (2020).

Mandlener and Specht (2020, p. 15) predict that the investment costs (EUR/kW) for a UPSHPP with a head height of roughly 420 m and new drifts for the lower reservoir would be 2000 EUR/kW. The previous paper from a similar group of authors (Montero, Wortberg, Binias & Niemann, 2016, p. 8) propose 815 EUR/kW for a UPSHPP with existing tunnels and 2700 EUR/kW for the one with new drifts. Menendez and coauthors (2017, p. 11) assume 1701 EUR/kW for a UPSHPP with new structures. As PČHE Rudar would require mostly newly excavated tunnels, the investment costs amounting to 1700 EUR/kW is assumed. Since the construction works would start in 2028, these costs could already decrease due to technological advancements. However, I have not envisioned such a reduction to hedge against potential upswings in costs. Building upon equation (2), the underground pumped storage hydropower plant Rudar with the installed capacity of 225MW situated in what would then be an abandoned Coalmine Velenje would thus cost EUR 382.5M. Green Shine would finance and consequently own one-fifth of the project, or EUR 76.5M, to be exact (i.e. part of the restructuring plan delineated in 3.2). It is expected that the power plant will be finished in 2032, one year before the JEK2, which could partly depend on UPSHPP for ancillary services.

Considering the ratio between generation, consumption and installed capacity from ČHE Avče (average for 2019 (Soške elektrarne Nova Gorica, 2019, pp. 22, 25) and 2020 (Soške elektrarne Nova Gorica, 2020, pp. 24, 27)), PČHE Rudar would generate 307 GWh of electricity per year and consume 403 GWh of electricity per year. Since positive and negative aFRR of ČHE Avče amount to approximately 10% of the installed capacity both in generation and pumping regime (conversation with a ČHE Avče representative), aFRR is more profitable than mFRR, future requirements for additional aFRR are going to be higher than for mFRR (see subchapters 5.7 and 5.8 on ancillary services) and as it is technically feasible to exceed the 10% of installed capacity dedicated to aFRR in ČHE Avče, PČHE Rudar is expected to offer ±45 MW (i.e. 20%) of aFRR. Proposing the exact size of mFRR is more challenging, as pumped storage hydropower plants do not provide only ancillary services but also work as regular power plants on the market, exploiting optimal market conditions. On top of this, the HSE Group, proprietor of ČHE Avče, supplies all the mFRR of its power plants to ELES together and then uses their capacities depending on specific market conditions (conversation with a ČHE Avče representative). This means that the exact numbers are difficult or even impossible to pinpoint. However, as the size of ČHE Avče's mFRR spans from ±90 to ±180 MW and future requirements for mFRR are estimated to increase only slightly in the future (see subchapter 5.8 on mFRR), I envision PČHE Rudar will dedicate ±22.5 MW (i.e. 10%) for mFRR. Table 25 summarizes the main figures.

Table 25: Main characteristics of PČHE Rudar

PČHE RUDAR	
CAPACITY (MW)	225
INV. COSTS (EUR/kW)	1,700
TOTAL INV. COSTS (EUR M)	382.5
CONSUMPTION (GWh)	403
GENERATION (GWh)	307
AUTOMATIC FRR (±MW)	45
MANUAL FRR (±MW)	22.5

Source: own work based on conversation with a ČHE Avče representative; Menendez et al. (2017); Soške elektrarne Nova Gorica (2019) and Soške elektrarne Nova Gorica (2020).

The investment would also be relatively economically viable. The power plant's revenues would mostly come from two sources: first, generating and selling electricity during peak hours on the imbalance and other markets; and second, providing ancillary services, namely mFRR and aFRR, to ELES. Regarding the former, Madlener and Specht (2020, p. 16) cite a complex market model by Kondiziella and Bruckner (2014), which "suggests a growing price spread between peak and off-peak prices at the spot market from about 30 EUR/MWh in 2010 up to 75 EUR/MWh in 2030". If I take the price spread of 60 EUR/MWh, 1,366 hours of full load generation (i.e. capacity factor of 15,5%) total cycle efficiency of 74% from ČHE Avče, and effective installed capacity of 112.5 MW (i.e. the non-mFRR part), the expected future revenue amounts to EUR 12.3M per year. As for the latter, ELES is currently paying 3 EUR/MW/h for +mFRR, 4 EUR/MW/h for –mFRR and 8 EUR/MW/h for ±aFRR (ELES, 2021b). Since the market for ancillary services is getting more and more pan-European and thus competitive, the price of future ancillary services could realistically fall by one third. The power station could thus earn EUR 5.1M per year by offering ancillary services to ELES. With these two sources of revenue, PČHE Rudar could make EUR 17.4M per year. The payback period, calculated in the most basic way merely for orientation, would be 22 years, whereas the plant would operate for 80 years (Pietzcker, Osorio & Rodrigues, 2021 p. 4; see Table 26). Since its role would be indispensable for a reliable and secure operation of the electric power system, the investment could potentially secure some additional funds from capacity remuneration mechanism, thereby further reducing the payback period.

Table 26: The economics of PČHE Rudar

PČHE RUDAR	
Adjusted price of positive mFRR (EUR/MW/h)	2.0
Adjusted price of negative mFRR (EUR/MW/h)	2.7
Adjusted price of aFRR (EUR/MW/h)	5.3
Revenue from ancillary services (EUR M)	5.1
Price spread (EUR/MWh)	60
Revenue from selling electricity (EUR M)	12.3
Total annual revenue (EUR M)	17.4
Payback period (yr)	22.0
Lifetime (yr)	80

Source: own work based on Madlener and Specht (2020); ELES (2021) and Pietzcker, Osorio & Rodrigues (2021).

4.6 Non-CHP combined cycle gas turbines

As coal phase-out is expected to predominantly occur by 2028 and completion of construction of JEK2 in 2033, the system would experience instability and heightened risk without new and reliable power plants that can generate electricity when most needed. As the need for CHP plants is limited (i.e. energy efficiency measures reducing the need for heat, etc.) and already covered above, as natural gas has a lower carbon footprint than coal (Table 2), as ecosystem damage of gas-fired plants is in many cases lower than the one from biomass-fired power stations and hydropower plants (Figure 2), as climate and biodiversity-friendly potential of biomass is already used (see subchapter 4.4 on CHP plants), as natural gas can be relatively easily decarbonised by hydrogen and SNG (see subchapter 5.4) and, last but not least, as gas-fired power plants generate electricity irrespectively of weather conditions and when most needed, combined cycle gas turbines present a sensible technology. Additionally, with high efficiency (60%) and a capacity factor of 0.5 until 2033 and 0.3 after 2033 (thus above and below 0.4 envisioned by International Energy Agency (2020, p. 419)), their cost prices are cost-effective (see subchapter 6.3.1 on cost prices). Building upon the CCGT case in Ljubljana, where gas turbines have installed capacity of 57 MW each, I propose additional 285 MW of CCGTs by 2028 (Table 27). Two would be located in Šaleška valley and three in Zasavje, thus in well-connected and already established Slovenian energy locations. Investments would also contribute to my plan's just transition and social pillar. Using capital costs from IEA (2020, p. 419) and equation (2), total investments costs would amount to EUR 255M.

Table 27: Combined cycle gas turbine: installed capacity, capacity factor and total investment costs

COMBINED CYCLE GAS TURBINES (CCGT)	
INSTALLED CAPACITY (MW)	285
CAPACITY FACTOR BY 2033	0.5
CAPACITY FACTOR AFTER 2033	0.3
INVESTMENT COSTS (EUR/kW)	893
TOTAL INVESTMENT COSTS (EUR M)	255

Source: own work based on International Energy Agency (2020).

4.7 Other energy sources

4.7.1 Biogas

In my predictions on future biogas use, I take the assumptions given by the NECP (Vlada Republike Slovenije, 2020, p. 146–147) and increase them. The NECP relied on the data from 2017 and foresaw that capacities would increase to 34 MW and 41 MW by 2030 and 2040, respectively, generating 170 GWh and 245 GWh of electricity. As installed capacities in 2020 already amounted to 36.8 MW (Agencija za energijo, 2021, p. 22), I believe that the value will increase to 42 MW and 50 MW in 2030 and 2040, respectively. These power stations would generate 210 GWh in 2030 and 299 GWh in 2040. Considering the investment costs from the NECP (Vlada Republike Slovenije, 2020, p. 128) and equation (2), the total expenses for 13.2 MW of additional biogas power plants would amount to EUR 42.9M (Table 28).

Table 28: Biogas power stations during the 2020-2040 period: installed capacity, generation and investment costs

BIOGAS POWER STATION	2020	2030	2040
CAPACITY (MW)	37	42	50
GENERATION (GWh)	97	210	299
INV. COSTS (EUR/kW)	3,250		
TOTAL INVESTMENT COSTS 2022-2040 (EUR M)	43		

Source: own work based on Vlada Republike Slovenije (2020).

4.7.2 Geothermal energy

The potential of geothermal energy for electricity generation in Slovenia has not yet been studied thoroughly. However, preliminary technical indications show that capacities are limited, even more so when economic factors are taken into account (Potarić, 2018; GEN skupina, n. d.). DEM has started working on two geothermal projects, one of which could result in the first binary cycle geothermal power station with a capacity of a few MW in Slovenia. The construction depends on the results of various studies that will assess the technical (the size and depth of potentially appropriate reservoir, its permeability and porosity, the enthalpy and chemical structure of fluid) and economic aspects of the project. As the construction of geothermal power plant would set a precedent in Slovenia, it would need to draw on national and European funds. Even if DEM's project is realized, the total potential of geothermal energy will still be objectively narrow (limited water source with a temperature above 100°C at the appropriate depth, frequently insufficient thermal fluid flow, high investment costs compared to other power stations etc.). In the optimistic scenario, some geothermal binary cycle power stations will be built in the future. However, as even such deployment would have relatively insignificant impact on the total electricity generation in Slovenia, I do not include this energy source in my further calculations. My proposal is aligned with the NECP (Vlada Republike Slovenije, 2020, p. 229), which envisions only a pilot project for a geothermal power station.

4.7.3 Open cycle gas turbines (strategic reserves)

Open cycle gas turbines represent flexible, fast-responsive power plants that provide adequate supply when required. These newly constructed or preserved power plants are started almost exclusively in difficult times and are therefore called strategic reserves (Mervar, 2021). As will be thoroughly explained and tested in subchapter 5.5, I propose setting up four 53 MW of OCGTs by 2030, totalling 212 MW. Three of them would be built in Brestanica and one in the Šaleška valley, accompanying 240 MW of the existing facilities (87 MW from 2033 onwards due to shutdowns). Taking the average investment costs for gas- and hydrogen-fired OCGTs (Pietzcker, Osorio & Rodrigues, 2021, p. 3) and block 7 of TEB (P. P., 2021) and employing equation (2), total investment costs for setting up four OCGTs would equal EUR 91M. As natural gas is still a fossil fuel, its usage should be decarbonised and replaced with hydrogen and SNG. Thus, if upgrades to fully hydrogen-run power plants amount to one-third of the initial investment costs (Goldmeer, 2019, p. 15), refurbishment costs for four strategic reserves would reach EUR 29M. Using equation (3) and a capacity factor of 0.025 for 2021 (Termoelektrarna Šoštanj), 0.25 from 2028 up to and including 2032 and 0.1 from 2033 onwards, which is reasonably low due to the inferior efficiency of these plants (see also EC, 2020e, p. 43), existing and new strategic reserves would generate 990 GWh of electricity in 2030 and 262 GWh in 2040.

4.7.4 Other

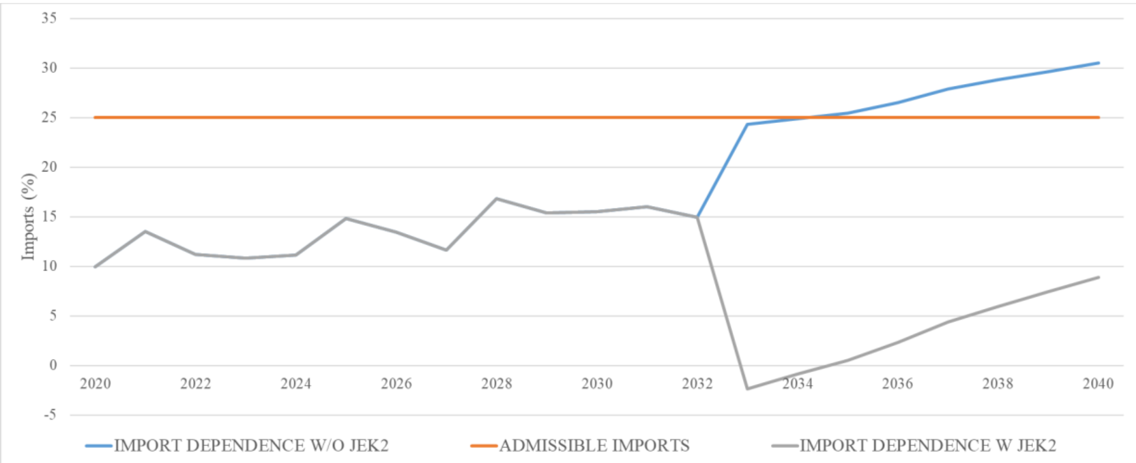
This category includes biomass power plants with a capacity of 16.4 MW (Agencija za Energijo, 2021, p. 22) and other power stations with a capacity of 4.4 MW (Agencija za Energijo, 2021, p. 22), which generated a total of 103.4 GWh of electricity in 2020. I assume that their capacity and electricity generation will remain the same throughout the observed period. Some older plants will be decommissioned, some new stations will be connected to the grid, and different, more non-conventional power stations using low-carbon energy sources will gradually and at least partly replace harmful power plants.

4.8 Nuclear energy

4.8.1 The necessity

The necessity of constructing JEK2 stems from two main factors. First, as seen in Figure 14, if we did not build it and left all things equal, Slovenia would become excessively dependent on imports, exceeding the import threshold of 25% of total yearly consumption defined in the NECP (the immediate increase in import dependence in 2033 would stem from a rise in electricity demand for electrolysers, essential for the decarbonisation of gas-based electricity supply) (Žerdin et al., 2021, p. 195). All the more, without nuclear energy, we would depend even more on hydrogen and SNG (see two electricity scenarios envisioned by NECP (Vlada Republike Slovenije, 2020)), increasing total electricity consumption and, consequently, import dependence. With JEK2, Slovenia would stay below the limit for the observed period, meaning that the power station would play an indispensable role in providing security of supply.

Figure 14: Import dependence with and without JEK2 (%)

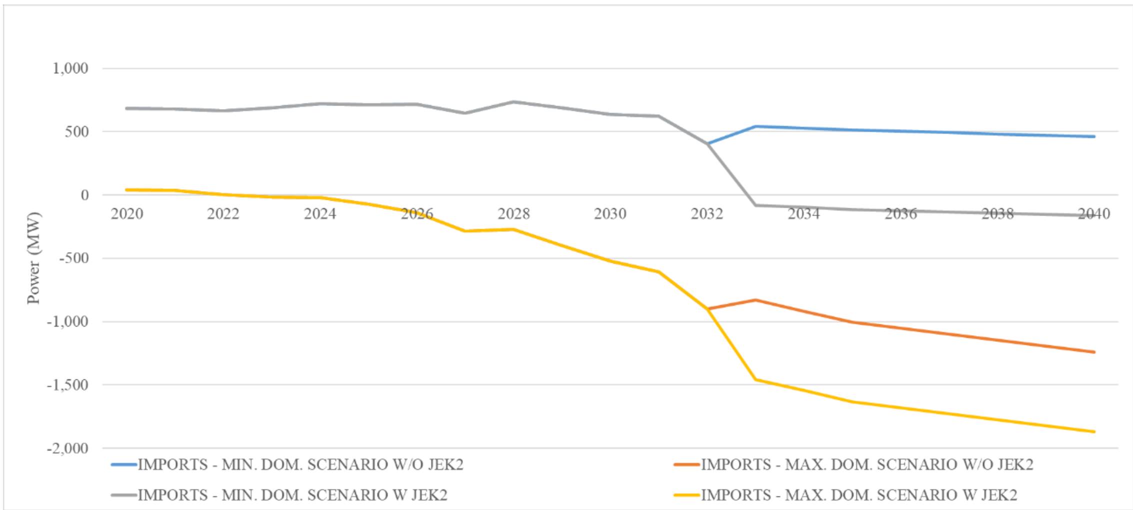


Source: own work.

Similar is true for peak load coverage. If I apply the approach and methodology explained in the subchapter 5.6 on peak demand, I get Figure 15, which plots import dependence during peak load hours throughout the 2022–2040 period. Four scenarios are illustrated: maximum domestic power output with and without JEK2 and minimal domestic power output with and without JEK2. In the worst-case scenario, minimum domestic power without JEK2, imports during peak load periods would stay close to 1,000 MW from the coal phase-out in 2028 onwards. Since the import net transfer capacities for the winter of 2019 were 3,110 MW (ELES, 2020, p. 104), the indicative values for 2030 are 5,080 MW (ELES, 2020, p. 104) and maximal import during peak load time frame in January 2019–2021 was 1,208 MW (9:00 on 23/1/2019) (ELES, n. d.), such hourly import dependence is still relatively manageable but risky and expensive, especially if persistent and in anticipation of further coal and nuclear phase-outs throughout Europe, rendering winter imports less stable.

Therefore, the construction of JEK2 is highly reasonable and desirable from the perspective of the system's security as it would prevent Slovenia from exposing itself to high levels of imports for an extended period of time.

Figure 15: Imports during peak load times with and without JEK2 (MW)



Source: own work.

4.8.2 The appropriateness

JEK2 also meets technical, economic, climate, social and nature conservation requirements and is ethically acceptable in terms of intergenerational justice. It is not the perfect solution from all perspectives and it does have some shortcomings (e.g. used fuel), but this holds true for each of the low-carbon technologies I have already presented. If I am to give an unbiased assessment of nuclear power, I should not consider it independently, but in juxtaposition to other solutions. Additionally, as has already been underlined in the introduction, I aim to assess different technologies from five standpoints, based on facts and hard data, and find the most sensible middle ground between what may, in some cases, be opposing tendencies.

From the climate perspective, it should be underlined that the nuclear power plant generates three tonnes of CO_2-equivalents per GWh of electricity generated over its lifecycle, i.e. one tonne less than wind, two tonnes less than solar and 31 tonnes less than hydropower (Table 2), which makes it the most climate-friendly energy source. Second, given that in the 1981–2019 period the median construction time for nuclear reactors worldwide was roughly seven to ten years (Statista, 2021), nuclear power can undoubtedly play an essential role in reaching net-zero carbon emissions by approximately 2040.

From a technical point of view, NPPs are a sound technology, as they provide reliable base-load energy with load-following characteristics when necessary (more in the following subchapter). Their electricity generation is weather-independent and not intermittent. Even more, they represent a stable source of electricity especially when the latter is needed the most (e.g. during peak load in the winter months). They can also provide various ancillary services, including FCR, aFRR, reactive power and voltage regulation, by which they contribute to the stability and reliability of the system. From the viewpoint of the electric power system, the most significant shortcoming of NPP is supposedly the immense mFRR capacity required to secure the system's reliability. However, this challenge could be solved relatively easily with regional regulation blocs, the pan-European market for ancillary services and by combining aFRR and mFRR needs (more in subchapters 5.7 and 5.8 on ancillary services).

From an economic perspective, my calculations of electricity cost prices of various power plants (see subchapter 6.3.1 on cost prices) show that the cost price of JEK2 would equal 80 EUR/MWh in 2040, which is more than the cost price of solar power stations and wind power plants, but less than of hydrogen-fired CHP plants, hydrogen-fired OCGT, hydrogen-fired CCGT and batteries. The differences are relatively moderate and cannot be used as a coherent argument against nuclear energy and in favour of, for example, solar power. Especially since cost prices do not account for system costs, which are significantly higher for solar and wind power stations than nuclear stations. For instance, the cumulative investment costs in different technologies covering peak surplus (solar) power output in warmer months would add up to EUR 2,287 M by 2040 (subchapter 5.1 on tackling surplus power output of SPPs). Additionally, total investment expenses in the electricity network, not included in the value above and partly related to the rapid increase in power plants using variable RES, would amount to EUR 6,081 M for 2022–2040 (subchapter 5.9 on investments in networks). If I add these system costs to cost prices, the electricity generated by an NPP would be at least cost comparable to the electricity produced by a SPP. Such reasoning is in line with Mervar's findings (2019b, p. 15) that the cost price of JEK2 would equal 89.5 EUR/MWh, whereas a SPP combined with battery storage (to incorporate system costs) would provide electricity at 128 EUR/MWh. Babič and Damijan (2020) came to a similar conclusion. They estimated that the cost price of JEK2 could even range somewhere between 43–52 EUR/MWh due to the current favourable financing conditions and low-interest rates. It can therefore be said that JEK2 is an economically wise investment.

Job creation is an aspect that permeates both the economic and the social pillars. In the USA, the construction of new solar and wind power plants generates 13.4 and 12.7 jobs per million USD, respectively, whereas the construction of nuclear power plants leads to 11.1 jobs per million USD (Pollin, Garrett-Peltier, Heintz & Hendricks, 2014, pp. 211, 216). Nuclear energy therefore creates approximately 15% less jobs than solar and wind energy per unit invested. One of the main reasons for such an outcome is that NPPs have a higher capital intensity than SPPs or WPPs. Job creation through operation and maintenance is identical (Pollin, Garrett-Peltier, Heintz & Hendricks, 2014, pp. 211, 216). However, Slovenia and other countries where nuclear power is part of the energy mix have already set up numerous jobs, educational programmes and institutions, all related to the existing NPP. In consequence, nuclear phase-out would cause unemployment and brain drain, while the construction of a new nuclear power plant would have a multiplier effect across the (local) value chain.

Another social aspect inevitably bound to nuclear energy is safety. Nuclear energy is one of the safest or the safest energy source measured by deaths from accidents and air pollution per TWh of electricity generated (Ritchie, 2020). Nuclear power causes 0.07 fatalities per TWh, including the casualties from the Fukushima and Chernobyl disasters as well as deaths from occupational accidents at mining or milling processes. The death toll of various RES is slightly lower (hydropower 0.02; solar 0.02; wind 0.04), whereas the rates for biomass, natural gas, oil and coal are incomparably higher (natural gas 2.8; biomass 4.6; oil 18.4; coal 24.6). However, above-mentioned nuclear energy rate is based on the numbers provided by the World Health Organisation (WHO), which estimated the death toll of the Chernobyl disaster at 4,000 (World Health Organisation, 2005). The WHO assessed the number of casualties with a highly contested linear no-threshold model (Kharecha & Hansen, 2013, p. D), also deemed as "very conservative" (Ritchie, 2020). Applying a more balanced approach, the United Nations Scientific Committee on the Effects of Atomic Radiation estimated that 43 deaths were conclusively attributable to the radiation from Chernobyl as of 2006, of which 28 were plant staff and first responders, and 15 were from the 6,000 people diagnosed with thyroid cancer (2011, pp. 64-65). With this data, the rate of 0.07 fatalities per TWh decreases to roughly 0.028, a number entirely comparable to RES. Either 0.028 or 0.07, it is undoubtedly clear that the death toll of nuclear energy per TWh is similar to the RES one and considerably lower than that of fossil fuels. In line with such findings, Kharecha and Hansen (2013), renowned scientists from NASA and Columbia University, estimated that nuclear power had prevented an average of 1.84 million air pollution-related casualties from 1971 to 2009 and could save additional 0.42–7.4 million lives by mid-century since NPPs would displace and generate electricity instead of much more harmful fossil fuels.

The last social aspect touches upon energy (and consequently broader social) democratisation, empowerment and a paradigmatic shift. In contrast to smaller power plants using vRES, NPP will most likely stifle, not expand energy democracy and will not empower the local people and communities. Suppose this power plant is perceived and implemented as *deus ex machina* or the *Promethean* solution and constructed in a vacuum without additional transformational measures, presented elsewhere (Mladi za podnebno pravičnost, 2022). In that case, only energy source and nothing else will change. Structural factors, driving the multiple crises we are in, would remain unaddressed, the same as systemic changes required for a gradual transition towards a post-capitalist society (Raworth, 2018). In the worst-case scenario, nuclear energy would only bring more of the same, only coloured in green. This concern was voiced by dr. Lučka Kajfež Bogataj, a renowned Slovenian climatologist and joint recipient of the Nobel Peace Prize in 2007, who stated that she did not have any substantial qualms about nuclear energy from the physical and technological perspectives, but she opposed it from the developmental viewpoint because it "promotes and stimulates old habits" (Zgonik, 2021). Therefore, it is of utmost importance that nuclear energy is conceived only as one of the essential constitutive parts of the broader transformational plan, comprised of progressive socio-economic and technological changes.

From a nature conservation perspective, as can be seen in Figure 2, published in the renowned scientific journal Nature Communication (Luderer et al., 2019), nuclear energy is one of the most nature-friendly low-carbon energy source. Brook and Bradshaw (2014), utilising land displacement as a "surrogate of broad-scale impacts on habitat" (2014, p. 4), concluded that of all the low-carbon technologies, NPPs have the most negligible impact on nature, which is also why their scientific article is entitled "Key role for nuclear energy in global biodiversity conservation". Researchers from The Nature Conservancy came to similar results (McDonald, Fargione, Kiesecker, Miller & Powell, 2009). To conclude, nuclear energy is undoubtedly one of the most nature-friendly low-carbon energy sources, and it could, coupled with better planning and siting of renewable energy power stations, alleviate and reduce potentially harmful effects of rapid renewable energy deployment on many globally important biodiversity areas.

Lastly, spent fuel and its storage presents one of the main drawbacks of nuclear energy as it remains a radiation hazard for an extended period of time. This topic also opens the question of intergenerational justice. To provide a comprehensive assessment, we need to put the quantity of spent fuel into perspective, which "produced annually from NPPs operating globally would cover a space the size of a soccer field to a depth of 1.5m" (International Atomic Energy Agency, 2016, p. 90). In comparison, the 2.12 billion tonnes of waste humanity dumps every year (The World Counts, n. d.) objectively pose a much greater threat to the current and future living world. Moreover, high-level wastes could be reduced by roughly 95% by using MOX fuel, which is technically perfectly feasible yet not economically viable due to low fuel prices (International Atomic Energy Agency, 2016, p. 91), and thorium-based reactors or integral fast reactors, still in the demonstration stages, generate little or no long-lived waste (Kharecha, Kutscher, Hansen & Mazria, 2010, pp. 4058–4059). As in either case some waste ought to be stored in deep, long-term underground geological repositories, states must make it their highest priority to regulate and ensure sufficient waste management funding. Considering that the quantity of spent fuel is negligible compared to the volume of waste produced annually, that the evolving technologies could reduce the quantity of radioactive waste, that nuclear energy is, as explained above, necessary and appropriate, and, finally, that the threats of biodiversity collapse and climate breakdown are existential and could dramatically affect the prospects of future generations, I believe that further use of nuclear energy and subsequent generation and storage of long-term nuclear waste is ethically justifiable.

4.8.3 Main characteristics of second nuclear power plant in Krško

According to the energy permit issued in July 2021 (Ministrstvo za infrastrukturo Republike Slovenije), a nuclear power plant with a third-generation (GEN III) pressurised water reactor

(PWR), a generating capacity of 1,100 MW and ±10% tolerance is projected to be built in Vrbina. It would generate 8,800 GWh of electricity per year and 1 GWh per hour with approximately 35% efficiency, which means that its capacity factor be above 0.91. It would provide ancillary services, namely FCR of ±2% of its nominal capacity and aFRR of ±10% of its nominal capacity. Additionally, it would not operate as a base-load power plant but as a load-following power station, ranging its power output from its technical minimum to the full nominal power with a power gradient of ±3 % per minute.

The characteristics of JEK2 proposed here are somewhat different from those delineated above. I suggest a joint venture where GEN energija would manage 880 MW (80%) and Hrvatska elektroprivreda 220 MW (20%) of JEK2. The power plant would nominally operate as a base-load power plant. However, as it would be attached to an electrolyser with an installed capacity of 220 MW (25% of GEN energija's share), it would function as a *de facto* load-following power station. The flow of electric energy to the electrolyser would diminish in times of high demand and high electricity prices and increase in times of low demand and low electricity prices. 1550 MW of envisioned electrolysers primarily used for coping with surplus power output from SPPs (subchapter 5.1) would deepen its load-following character. The capacity factor assumed is 0.95, as the electrolysers would make it possible to use the power plant's maximum power output continuously except during regular refuelling processes (Naterer et al., 2013 in El-Emam & Özcan, 2019, p. 595). In the Slovenian case, based on equation (3), 1100 MW would generate 9,160 GWh of electricity and not 8,800 GWh as stated in the energy permit. The latter value, which translates in the capacity factor of 0.91, seems highly optimistic given that (load-following) nuclear reactors in France have a capacity factor of 0.76 (Boccard, 2013, p. 7) and that solar energy penetration of as little as 20% is expected to reduce NPP's capacity factor by 23% (International Atomic Energy Agency, 2018, p. 97). My proposal is based on several arguments.

First, when we consider that Slovenian power plants compete on the European electricity market and adjust their power output accordingly, and Slovenian suppliers do not necessarily provide Slovenian electricity, but purchase electricity all around Europe in search of the lowest prices, the popular demand for a full independence electricity-wise seems somewhat odd and out-of-date. Slovenia already has the capacities to be completely independent (Žerdin et al., 2021, p. 196), but the pan-European market conditions prompt Slovenian power plants not to operate at their maximum power output, and Slovenian suppliers to import electricity rather than buy it domestically. Such a setting has established lower prices for households and industries, improved welfare and stimulated national economic development. Or as mag. Mervar has put it concisely, "we are already practically independent, if we forget about economics" (Janež & Kukovičič, 2017, p. 6). Nevertheless, considering that electricity is a specific commodity, local power plants have an important multiplier effect on the whole economy, that crises give rise to energy nationalisms and that excessive import dependence puts security of supply under immense risk, the objective of covering most – but not necessarily all – national consumption by domestic generation seems sensible. With the proposed JEK2, import dependence would vary between -2–9% from 2033 (i.e. the date of its completion) until 2040, which is reasonable, in line with past figures and well below the import threshold of 25% of yearly consumption given in the NECP (Žerdin et al., 2021, p. 195). Second, with JEK2, the Slovenian electric power system would be robust enough to cope with peak load (see Figure 15). Third, the bigger the installed capacity, the bigger the need for mFRR and the bigger the costs. If the plant's specifications were the same as stated in the energy permit, the required mFRR would increase up to 506 MW (my calculations based on the methodology presented in subchapter 5.8 on mFRR), whereas 256 MW of mFRR would be needed if my recommendations were implemented. Fourth, inviting Croatia to become a shareholder in JEK2 would make further existence of the SCB block, uniting Croatia, Bosnia and Herzegovina, and Slovenia in mFRR sharing, much more likely. Since the block enables lower national requirements for mFRR, its continued presence is of utmost importance. Hrvatska elektroprivreda has already shown interest in the project (Trkanjec, 2021). Fifth, excessive reliance on a single power plant makes the system more vulnerable. As shown in the subchapter 6.1 on future electricity balance, JEK2 would cover a moderate 26% of final electricity consumption in 2040, which is significantly different from, for example, the Babič and Damijan's scenario (2020), where JEK2 would meet roughly 60% of the entire Slovenian electricity consumption. Sixth, all four neighbouring countries are currently net electricity importers (ELES, 2020, p.108), which is not going to change at least until 2025 according to some projections (ELES, 2020, p.112) or even in the following decades according on their own NECPs (conversation with a GEN-I employee). However, as projections by the end of the century, when JEK2 would be phased-out, are practically impossible, betting on future exports throughout the century would be risky and, in my opinion, unwise. Seventh, investing in JEK2 without the involvement of foreign countries would increase the initial expenses and could crowd out investments in other low-carbon energy sources. Eighth, I propose that two small modular reactors (SMR), which are expected to become commercially available in the first part of the 2030s (Nuclear Energy Agency, 2021, p. 47), with 250 MW of installed capacity each be built during the 2041–2044 period (subchapter 6.1 on electricity balance). In this way, Slovenia could reap some of the benefits of technological development and economies of scale. Essentially, due to their size, SMRs present fewer challenges and problems than larger nuclear reactors. With two SMRs built before 2045, JEK2 could be smaller. Last but not least, as thoroughly explained in the nine arguments below, base-load NPPs attached to an electrolyser are economically and technically superior to load-following NPPs and are more environmentally friendly. The latter aspect in particular is crucial because natural gas is expected to be replaced by hydrogen and SNG, which will make low-carbon hydrogen production highly valuable.

I presume that the construction of JEK2 will start in 2026 and end by late 2032, which is seven years, one more than was estimated by Lazard (2020, p. 18) and the U.S. Energy Information Agency for "n-th of a kind" nuclear reactor (ENCO, 2020, p. 29). Since construction works would begin in 2026, a third-generation JEK2 would then be considered as “n-th of a kind” project. In my case, the preparation period would last four years (2022–2025). As the first steps have been already made and the existing nuclear site would be used, the time frame is feasible (ENCO, 2020, p. 27). A potential referendum, if it would be necessary, should thus be carried out at the end of 2023. Both the preparation and the construction periods seem even more achievable as my plan hopefully provides an acceptable preliminary scenario for various stakeholders, reinforcing and broadening the support. The entire process would stretch over 11 years and end by late 2032, thus later than GEN energija and ELES predictions and earlier than GEN-I assumption (ELES, 2020, p. 88).

Based on IEA’s EU Sustainable Development Scenario (2020, p. 419), I presume the capital costs will amount to 5,270 EUR/kW in 2026. Building upon equation (2), if JEK2 has the capacity of 880 MW, it will cost EUR 4,638M (Table 29).

Table 29: Second nuclear power plant in Krško (Slovenian share) – main characteristics

SECOND NPP KRŠKO (Slovenian share)	
INVESTMENT COSTS IN 2026 (EUR/kW)	5,270
CAPACITY (MW)	880
TOTAL COST (EUR M)	4,638
GENERATION – total (GWh)	7,328
GENERATION – direct electricity use (GWh)	5,496
GENERATION (kt H2)	40

Source: own work based on International Energy Agency (2020); ENCO (2020); Lazard (2020) and El-Emam & Özcan (2019).

4.8.4 Hydrogen production, alkaline electrolyser attached to JEK2 and usage of waste heat in heating systems

The energy permit was issued for a load-following power station (Ministrstvo za infrastrukturo Republike Slovenije, 2021, pp. 1, 4) that would adjust its power output to the fluctuating demand. Since contemporary electric power systems are becoming increasingly dynamic, load following, flexibility and other similar characteristics have been gaining ground and nuclear fleets of some countries, notably France (Morilhat, Feutry, Maitre & Favennec, 2019), have already adapted to such reality. Nowadays, ever more electric utilities, international institutions and countries have been reconsidering the role of nuclear energy in the (future) electric power system. They perceive NPPs in a more dynamic and hybrid way, and believe that they could provide, among other things, heat, hydrogen and load-following capacities (Patel, 2019), a view shared by dr. Tomaž Žagar, president of the Nuclear Society of Slovenia (2020).

In line with such views, there are nine reasons why I believe JEK2 should operate as a base-load power plant that primarily generates electricity and hydrogen as a by-product and not as a load-following power plant adjusting its power output to the daily and seasonal consumption patterns. The latter option has been, as has already been mentioned, proposed by GEN energija in energy permit. When NPP is attached to an electrolyser, it *de facto* functions as a load-following power station. Consumption in the electrolyser decreases in times of high demand and high electricity prices and increases when demand and prices are low. The 220 MW of electrolyser capacity attached to JEK2 and the 1,550 MW of the electrolysers primarily dedicated to coping with the surplus power output from SPPs (subchapter 5.1) would provide more than enough capacities for JEK2 in times of low electricity prices.

First, with an electrolyser, an NPP can use its maximum power continuously and does not need to adjust it to the current load demands. Consequently, the capacity factor can surpass 0.95 (Naterer et al., 2013 in El-Emam and Özcan, 2019, p. 595), which makes the project more viable economically. All the more so because up to 87% of nuclear costs are fixed (Nuclear Energy Agency, 2020, p. 31), making reductions in power output highly undesirable. The high capacity factor is thus one of the crucial prerequisites for the economic viability of an NPP. Whereas a base-load NPP connected to an electrolyser can reach a capacity factor of 0.95, French load-following NPPs have a capacity factor of only 0.76 (Boccard, 2013, p. 7). Additionally, solar energy penetration of as little as 20% can reduce an NPP's capacity factor by 23% (International Atomic Energy Agency, 2018, p. 97). Second, whereas hydrogen would be a source of additional revenue, it is unlikely that the transmission system operator or other institution would award the load-following characteristic of the NPP. Also, other power plants holding the same role in the system, for example TEŠ, have not been financially compensated. Third, when power output ramps up and down, various pieces of equipment wear down faster, translating into higher maintenance and operation costs (International Atomic Energy Agency, 2018, p. 101). Fourth, I propose building 1,550 MW of electrolysers dedicated to coping with surplus solar power output during the warmer months (subchapter 5.1). This should be done irrespective of JEK2, even though the latter could use the electrolysers in times of low electricity demand and low electricity prices. Even partly co-founding these investments would give the JEK2 a competitive advantage, lowering the required investment costs in electrolysers. Fifth, one of the most critical factors determining hydrogen costs is the utilisation rate of an electrolyser (Lazard, 2021, pp. 9–11), which means that if the flow of the electricity from SPPs, JEK2 and other sources is relatively stable, the costs will drop and hydrogen generation will be more viable. Sixth, if I take a conventional alkaline electrolyser with an investment cost of 289 EUR/kW (subchapter 5.4), the cost price of electricity generated by JEK2 at 80 EUR/MWh (subchapter 6.3) and apply the methodology presented in subchapter 6.3.1, the cost price of hydrogen produced by the electrolyser attached to the nuclear reactor would amount to 4.2 EUR/kg. The value would be above the costs of fossil fuel-based hydrogen but below the expected future retail prices (see subchapter 5.4.3). Through economies of scale, learning by doing, innovations, public policies stimulating low-carbon hydrogen development while discouraging fossil fuels-based hydrogen production (e.g. high carbon taxes), green hydrogen can soon become cost-competitive (Bloomberg NEF, 2020). Moreover, if JEK2-based hydrogen is combined with hydrogen generated by RES and grid electricity, the weighted cost price of hydrogen is expected to equal 2,9 EUR/kg in 2040 (subchapter 5.4.3). This would – in case of stimulative green policies – make it more cost-competitive with fossil fuel-based hydrogen. Seventh, since hydrogen is crucial for the decarbonisation of gas-based electricity generation and hard-to-abate sectors, the demand for zero- or low-carbon hydrogen is expected to grow dramatically in the coming years and decades (European Commission, 2020d; Bloomberg NEF, 2020). Eighth, only alkaline or PEM electrolysers can be used for GEN III reactors with an outlet temperature of around approximately 300°C (Pinsky, Sabharwall, Hartvigsen, & O'Brien, 2020, p. 3) since the external inflow of heat potentially used in solid oxide electrolyser cell (SOEC) is most likely uneconomic (see subchapter 5.4.1). Alkaline electrolysers are mature and reliable, operate at the temperature of 40–90°C (El-Emam & Özcan, 2019, pp. 597–598), provide long-term stability and are comprised of non-noble materials. Importantly, they come at lower investment costs (EUR/kW) than PEM electrolysers, and their characteristics for the provision of ancillary services are not drastically worse. Its load range stretches between 15 and 100% nominal load, its production can ramp up and down by 0.2–20% per second, and it can start or shut down its operation in 1–10 minutes (International Renewable Energy Agency, 2018, p. 23). Similarly to the PEM one, it responds to a frequency dip of 0.2 Hz by reducing its power consumption in under a second (International Renewable Energy Agency, 20219b, p. 123). These characteristics make it an up-and-coming option for the provision of ancillary services, which would (financially) benefit the owner as well as the electric power system as a whole. Since an electrolyser connected to JEK2 would have a high capacity factor, hence a high utilisation rate and high availability factor, I assume it could provide 44 MW of aFRR (i.e. 20% of its nominal power) and 22 MW of mFRR (i.e. 10% of its total capacity). Last but not least, potential problems with outages of electric lines will be bypassed by building the electrolyser next to JEK2. To conclude, these nine arguments prove the economic, technical and environmental sensibility of dedicating 220 MW of JEK2's installed capacity to hydrogen production using alkaline electrolyser, with the exact power output depending on the particular (market) conditions.

Basing my calculations on the results and methodology from the subchapter 5.4, electrolysers connected to JEK2 would deliver roughly 40 kt of hydrogen in 2040, representing around 22% of all hydrogen generated in Slovenia. JEK2 and its electrolyser would thus occupy an important role as zero-carbon hydrogen provider and facilitator of the decarbonisation of gas-based electricity production and hard-to-abate sectors.

The total investment costs calculated based on the capital costs of utility-scale alkaline electrolysers provided by IRENA (2020, p. 72), the future reduction pace given by Bloomberg NEF (2020, p. 5) and equation (2) would amount to EUR 66.7M (Table 30). More on the investment costs and the future of electrolysers in Slovenia can be found in subchapter 5.4.

Table 30: Alkaline electrolyser connected to JEK2 – main characteristics

ALKALINE ELECTROLYSER CONNECTED TO JEK2	
CAPACITY (MW)	220
INV. COST (EUR/kW) in 2030	303
TOTAL INVESTMENT COSTS (EUR M)	66.7
GENERATION (kt H_2)	39.6
SHARE OF TOTAL SLO H_2 GENERATION (%)	22%

Source: own work based on International Renewable Energy Agency (2020) and Bloomberg NEF (2020).

Since third-generation pressurised water reactors have an outlet temperature of roughly 300°C (Pinsky, Sabharwall, Hartvigsen, & O'Brien, 2020, p. 3) and alkaline electrolysers generally operate at the temperature of 40–90°C (El-Emam & Özcan, 2019, pp. 597–598), excess waste heat (i.e. not used in the electrolyser) would provide heat to the industry and households. This would represent an additional source of revenue for the JEK2 and provide an environmentally friendly heating option. Such usage of waste heat is also mentioned in the energy permit (Ministrstvo za infrastrukturo Republike Slovenije, 2021, p. 5).

4.8.5 Requirements for manual frequency restoration reserves

Considering the discussion and calculations presented in subchapter 5.8, JEK2 will cause an increase in mFRR requirements by only 6 MW, i.e. from the current 250 MW to 256 MW. Providing 256 MW of mFRR should not present a significant problem for the electric power system of 2033.

To sum up, the *de facto* load-following second nuclear power plant in Krško would become a safe, abundant and cost-effective source of low-carbon electricity, especially indispensable during the winter. It would provide essential ancillary services without causing a significant increase in mFRR required, enhance security and reliability of supply, help solve the seasonality problem, accelerate renewable energy deployment, generate hydrogen for various actors and stimulate the promising national hydrogen industry. All this cost-effectively with moderate cost price (80 EUR/MWh, see subchapter 6.3.1) and low system costs. Lastly, it would supply heat to industrial and/or household users in an environmentally friendly manner.

5 RELIABILITY, SECURITY AND STABILITY OF ELECTRICITY SUPPLY AND ELECTRIC POWER SYSTEM

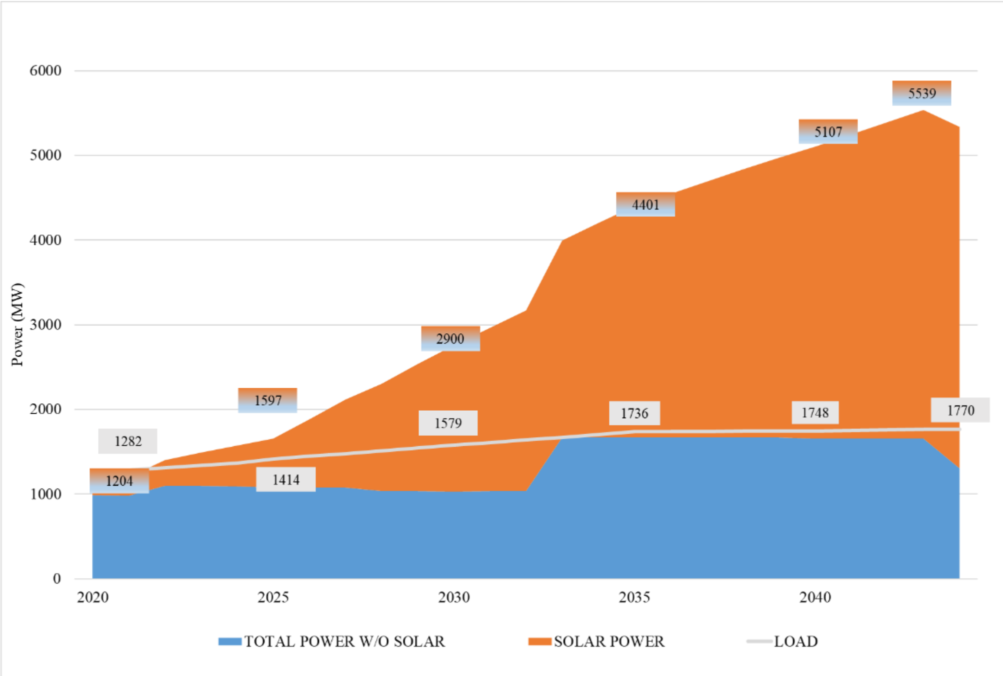
5.1 Maximum excess (solar) power during the May Day holidays

The greatest challenge regarding solar power will occur during May Day public holidays, when load is at its lowest point in the year because most of the industries and administration offices are temporarily closed and electricity power generation from SPPs is already considerable (conversation with a GEN-I employee). If the sun is out on those days, the differences between excess (solar) power and load will be the largest. It is for this reason that this chapter will be dedicated to estimating surplus hourly power above hourly load during the May Day holidays and, in the next step, considering what can be done with such a surplus.

I have calculated the hourly load for the May Day holidays based on the data from ELES, Borzen and the Energy Agency; I took the hourly average for the 11:00–14:00 time frame primarily for 2019 to avoid the effects of the pandemic. Future hourly load was estimated by increasing the present hourly load by the same rate as the yearly rise in total consumption. With the exception of solar energy, hourly generation from various power plants and energy sources was taken from ELES and Borzen. To account for potential fluctuations in hydrology, a power output of HPPs was estimated based on the information from 2019, 2020 and 2021, the years for which ELES data is available. For solar power, the European Network of Transmission System Operators for Electricity (ENTSO-E) database was utilised. The capacity factor was estimated as the average of the fifth of the highest capacity factors during the May Day holidays from 2018 to 2020. The value obtained equals 0.58, which is greater than the 0.55 used by GEN-I (conversation with a GEN-I employee) and lower than the 0.7675 coincidence factor used by Mervar (2019a, p. 6).[17] Additionally, based on the 15% decrease in the flow of Slovenian rivers during the period of 1961–2015 and future modelling estimates (Agencija Republike Slovenije za okolje, 2018, pp. 39, 144), I reduced the power output of HPPs by 2.5% per five years. Table 31 and Figure 16 show the maximum excess hourly power above hourly load during the May Day holidays for the 2020–2044 period.

17 However, the meaning of Mervar's coincidence factor is not entirely clear as it occurred at 20:00, 22:00 and 10:00 during the 2014–2017 period (2019a) and not around midday when solar power stations operate at maximum capacity. It seems that his concept denotes the highest share of all installed SPPs operating simultaneously (irrespective of their power output). If this is the case, it can be concluded that the coincidence factor is lower for noon and early afternoon due to physical and meteorological reasons – the atmosphere is more stable in the morning when solar irradiance is lower and the ground is colder. Around noontime and early afternoon, when the soil is already warmer, solar irradiance is stronger and causes more evapotranspiration, and more heat is already accumulated in the atmosphere. Consequently, cloud formation is more likely, and the coincidence factor of solar power plants decreases. Additionally, the coincident factor will presumably decrease as SPPs are extensively constructed in various parts of Slovenia.

Figure 16: Maximum excess (solar) power from 2020 to 2044 (MW)



Source: own work based on ENTSO-E database; ELES database; Borzen and Energy Agency.

Table 31: Maximum excess (solar) power from 2021 to 2044 (MW)

MAXIMUM EXCESS (SOLAR) POWER (MW)	2021	2025	2030	2035	2040	2043	2044
TOTAL POWER W/O SOLAR	985	1079	1030	1667	1653	1653	1308
SOLAR POWER	219	576	1727	2734	3454	3885	4029
LOAD	1282	1414	1579	1736	1748	1764	1770
DIFFERENCE	-78	241	1178	2665	3359	3774	3567

Source: own work based on ENTSO-E database; ELES database; Borzen and Energy Agency.

As seen in the Figure 16, in a few years, the projected deployment of SPPs will already cause excess power output around noontime during the May Day holidays. Interestingly, the problem will not be alleviated if coal is phased out in 2028 and Nuclear Power Plant Krško closes in 2043, as these two events have insignificant effects compared to the sheer installed capacities of projected SPPs. In consequence, I will attempt to assess, explain and propose solutions for tackling such troublesome circumstances through exports, demand-side management, pumped storage hydropower stations, storage capacities of existing hydropower plants, temporarily disconnecting renewable energy power plants from the electricity network, battery storage and electrolysers.

5.1.1 Exports

The easiest way to solve the problem would be to export all the excess electricity. If we look at the energy map of Europe, we see that investments in RES have increased extraordinarily in Western, Central and Southwestern Europe, which has caused considerable amounts of electricity to be imported by the countries of Southeastern Europe (ELES, 2020, pp. 103–109). This situation has not been brought about by a lack of power capacities but because incumbent power plants have not been able to compete with low and frequently subsidised electricity from foreign wind and solar power stations. The utilisation of transmission lines and the direction of electricity transit in Slovenia tell a similar story. In the past, electricity was transferred mainly in the NW–SW direction in Slovenia. Nowadays, the direction has changed. Electricity flows in the NW–SE or even W–E direction (ELES, 2020, pp. 103–109). These trends are expected to continue and intensify. The new 2 x 400 kV Cirkovce-Pince power line connecting Slovenia and Hungary from 2022 onwards will only accelerate the process. In 2019, the export flow to Croatia averaged at 235 MW and peaked at 1,356 MW, while indicative values of export net transfer capacities to Italy, Austria, Croatia and Hungary are expected to reach 800, 2,000, 2,000 and 1,200 MW, respectively, in 2030 (ELES, 2020, p. 104). However, even though the cross-zonal transmission capacities are sufficient, exports are limited by other factors as well. Appropriate weather conditions likely coincide in a considerable part of Europe, which makes it highly likely that a considerable share of EU countries will want to export simultaneously. More importantly, on a sunny day, as observed in the Figure 16, negligible installed capacities of solar power plants already generate excess power and create the need for exports. Thus, hinging upon considerable amounts of exports seems risky and unfounded. I therefore assume that exports, mainly to the countries of Eastern Europe and Western Balkans, will reach 750 MW by 2027 and will then decrease to 700 MW in 2030, 550 MW in 2035, 400 MW in 2040 and 250 MW in 2045.

5.1.2 Demand-side management

As demand-side management will be thoroughly discussed in the subchapter 5.2, this paragraph will only give a brief summary. I used the numbers and availability factor from Consortium's scenario (conversation with an ELES employees) and increased them by half based on various studies and policy proposals (Sistemski operater distribucijskega omrežja, 2020, p. 93; ELES, 2020, p. 81; Elektro Maribor, 2019; iEnergija, n. d.; Smart Energy Europe, 2021, pp. 5–6; Lagler et al., 2014). I also took the investment costs given by Sistemski operater distribucijskega omrežja (2016, p. 31) and increased them by EUR 20M as the study failed to include all the necessary expenditures. According to my calculations, the total expenses for a fully functional DSM would amount to EUR 80.4M, which translates into 53.6 EUR/kW (Table 32), making it the most cost-effective solution for coping with excess power. As a working presumption, demand-side management providing full available capacity for five hours and half of its total potential for two hours per day has been assumed.

Table 32: Demand-side management, its investment costs and role in coping with excess solar power

DEMAND SIDE MANAGEMENT	2025	2030	2035	2040
CAPACITY (MW)	30	300	750	1,500
SUMMER AVAILABILITY FACTOR	0.15			
DAILY POTENTIAL	100% 5h; 50% 2h			
INV. COSTS (EUR/kW)	53.6			
TOTAL INVESTMENT COSTS (EUR M)	80.4			

Source: own work based on conversation with ELES employee; Sistemski operater distribucijskega omrežja (2016 and 2020); ELES (2020); Elektro Maribor (2019); iEnergija (n. d.); Smart Energy Europe (2021) and Lagler et al. (2014).

5.1.3 Pumped storage hydropower stations

Another solution to tackle the problem of excess (solar) power are pumped storage power stations. I have assumed an availability factor of 0.9, the same value as Consortium has suggested for electrolysers (conversations with ELES employees). ČHE Avče, with an installed capacity of 180 MW in generation regime and 2.8 GWh of storage capacity, has already been built, and PČHE Rudar, with an installed capacity of 225 MW and 1.1 GWh of storage capacity, is expected to be constructed by 2032 (subchapter 4.5). These two power stations could thus provide 365 MW to tackle excess (solar) power and accumulate almost 4 GWh of excess electricity.

5.1.4 Storage capacities of hydropower plants

Hydropower plants offer another sensible storage option as the basins could be emptied out in the morning, filled back up during the day and then emptied again late in the evening. Since run-of-the-river-reservoir hydropower plants are the most common type in Slovenia, accumulation capacities are not abundant. Nevertheless, the existing hydropower stations on the Drava river can amass roughly 2.2 GWh of electricity (conversation with a DEM employee). In theory, storage capacities could be filled or emptied in 5–10 hours, which means 314 MW are available. As hydropower plants on the lower Sava river can accumulate 376 MWh (conversation with a HESS employee) and their basins have similar characteristics as those on the Drava, roughly 54 MW are available on the lower Sava river. Storage capacity of hydropower plants on the Soča amounts to 405 MWh (conversation with a SENG employee). If I extrapolate these values to the remaining few hydropower plants, I get a total of roughly 400 MW and 3.3 GWh of capacities. Taking the availability factor of 0.75, as run-of-the-river-reservoir hydropower plants are less appropriate for such purposes as pumped storage plants (conversation with s HESS employee), the existing HPPs could provide 300 MW to deal with surplus solar power. In energy terms, they can accumulate roughly 3.3 GWh of excess electricity.

Even after exports, demand-side management, pumped storage hydropower stations and accumulation capacities of the existing hydropower plants are considered, the Slovenian electric power system would still face surplus (solar) power of 1,338 MW in 2035, and 2,069 MW in 2040.

5.1.5 Disconnecting renewable energy power plants from the grid

The next option would be to shut down various power plants temporally. In 2028, coal phase-out will have already happened. Gas power stations with high marginal costs do not typically operate during high production from SPPs. Nuclear Power Plant Krško is not designed to operate as a load-following power station, which leaves us with various renewable energy power plants. Hydropower plants have low operation and maintenance expenses (International Renewable Energy Agency, 2012, pp. 17–30), no fuel expenses, and their marginal costs are low, making water spillage an unfavourable option. Even more so as cost prices of existing HPPs range between 20–40 EUR/MWh (Mervar, 2014, p. 103). The same holds for solar power stations.[18] Thus, it is sensible to use excess electricity for other purposes and not disconnect power plants from the grid. One promising solution is hydrogen generation using excess electricity from hydro and/or solar power stations potentially combined with grid electricity. The Jožef Stefan Institute conducted a study for the hydropower company HESS and found that already today, a small electrolyser (1 MW) with an electricity price of 50 EUR/MWh could produce hydrogen at a price of 3.86 EUR/kg (Srnovršnik, 2021). Taking 6 EUR/kg as the selling price, additional income would reach 42.8 EUR/MWh (Srnovršnik, 2021). The economic prospects of similar projects will presumably improve in the following years. However, the likelihood of such investment is limited as its economic viability significantly depends on a relatively high utilisation rate, requiring also the use of more expensive grid electricity. Therefore, it is yet to be seen if electrolysers attached to HPPs will be set up. Whatever the case may be, during relatively sunny days of warmer months (see Figure 17), the need for short-term storage will be limited, and electrolysers will not be able to consume all the excess electricity, making the option of disconnections highly likely or even necessary. Near-term storage will gain importance on cloudy days or when a clear day is followed by a cloudier period as it can store enough excess electricity for electrolyser to take up the remainder. Consequently, there will be no need to spill water over the gates of the discharge paths or disconnect SPPs from the grid. However, as a working assumption, I presume that 200 MW in 2030, 250 MW in 2035 and 300 MW in 2040 of renewable energy power stations will be shut down during periods of many consecutive sunny days.

The last two options are batteries, which would take care of daily and, at most, weekly electricity imbalances, and electrolysers that would produce hydrogen from excess electricity and enable seasonal storage. Installed capacity of electrolysers will be estimated

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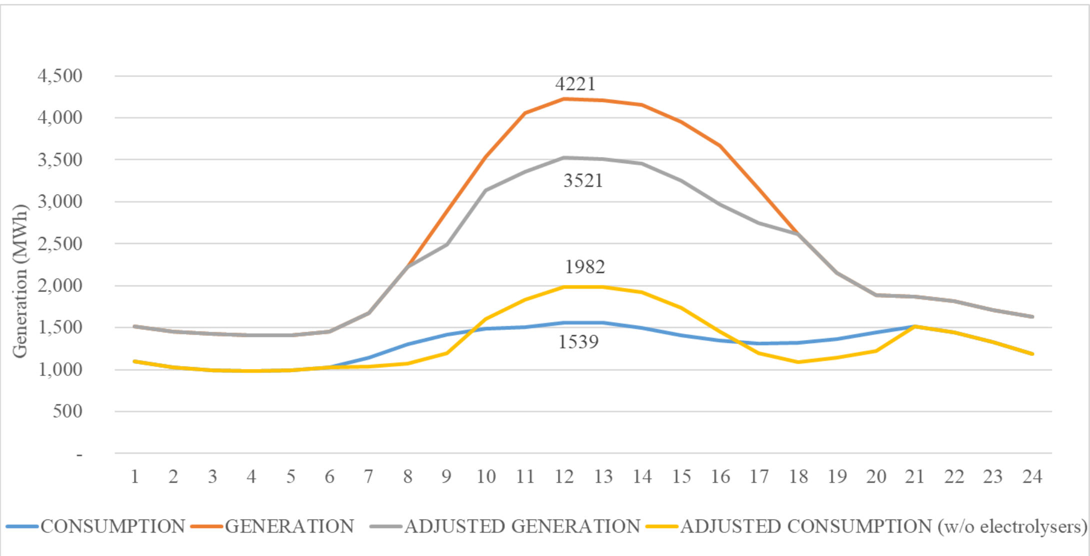
18 To be precise, as HPPs must pay for the water used due to water concession, their marginal costs surpass those of solar or wind power stations, and water spilling becomes more favourable compared to disconnecting solar power plants from the grid.

by constructing and overlapping the forecasted daily electricity consumption diagram with the daily electricity generation diagram for the May Day holidays in 2040. Except for solar energy, data has been taken from ELES, Borzen and Energy Agency, and extrapolated to the year 2040 based on the projected development of the electric power system. To obtain average hourly capacity factors of SPPs, values between 55–75% of the sunniest days during the May Day holidays in 2018–2020 were taken from the ENTSO-E database. This range was chosen for two main reasons. First, since electrolysers are economically viable only when the utilisation rate is relatively high, it would not be economically sensible to target and cover maximum excess power, which only occurs once or a few times per year, as that would lower the utilisation factor. On the other hand, as the opportunity costs of not using excess power are high, we must strike a balance between the electrolyser's size and utilisation rate. Second, since the May Day holidays are the time when the difference between generation and consumption is the most significant, it would not be reasonable to base the predictions on the sunniest days of this period. In that regard, it seems sensible to take the 55–75% interval.

Figure 17 shows a diagram of daily consumption and generation for a modestly clear day during the May Day holidays in 2040. Slovenia will be more than self-sufficient throughout the day, making intra-day storage futile. Additionally, it is questionable whether near-term storage will be needed for the subsequent days if clear days precede and succeed a relatively sunny day. Therefore, if I take 8 hours of 400 MW of exports, 5 hours of 225 MW and 2 hours of 112.5 MW of demand-side management, 6 hours of 300 MW of disconnections, and 3 hours of 200 MW and 2 hours of 100 MW of short-term storage, I get the adjusted electricity generation and consumption curves presented in the Figure 17.

Figure 17: Daily diagram for a modestly sunny day during the May Day holidays in 2040 (w/o electrolysers) (MWh)



Source: own work.

5.1.6 Electrolysers and hydrogen storage and transportation

As seen from the Figure 17, most significant difference between consumption and adjusted generation would amount to around 1,500 MW. Notably, the quantity of surplus electricity would be relatively stable and flat from 10:00 to 17:00 and only slightly lower at 9:00–10:00 and 17:00–18:00, making production by electrolysers more economically efficient. Thus, I propose electrolysers with 1,550 MW. As will be further explained in subchapter 5.4, 1,163 MW of alkaline electrolysers and 388 MW of PEM electrolysers are projected by 2040. Half of the capacities would be situated in the Šaleška valley and the other half in the Zasavje region. The deployment path until 2040 is outlined in the Table 33. When I compare Consortium's figures (conversation with a GEN-I employee) with my own, I can see some similarities: the Consortium's scenario predicts 10 MW of electrolysers by 2025, 100 MW by 2030, 600 MW by 2035 and 1,300 MW by 2040, which further reinforces the validity of my approach. As explained in subchapter 5.4, EUR 383M will be required to finance the investments in electrolysers by 2040, excluding the one connected to JEK2.

Table 33: Electrolysers for coping with excess solar power from 2022 to 2040 (MW)

ELECTROLYSER (MW)	2025	2030	2035	2040
Alkaline electrolyser	7.5	93.8	487.5	1,162.5
PEM electrolyser	2.5	31.3	162.5	387.5
TOTAL	10.0	125.0	650.0	1,550.0

Source: own work based on International Renewable Energy Agency (2018) and El-Emam & Özcan (2019).

Extensive quantities of hydrogen produced during the warmer months can be stored, exported or used in the near term. As will be explained thoroughly in the subchapter 5.4 on hydrogen, Slovenia is expected to produce 177 kt of hydrogen in 2040 (including hydrogen from electrolysers connected to JEK2). Storage facilities required for a quarter of this quantity are presumed (i.e. 44 kt). In this respect, the rock caverns at PV would offer some distinct benefits, but they would most likely cost more than the storage capacity in depleted natural gas reservoirs in Eastern Slovenia. As calculated in the subchapter 5.4.5, hydrogen storage site in Petišovci, Paka, Ratka and Lovaszi depleted gas reservoirs would cost EUR 182M, and an additional EUR 148M would be needed to repurpose the 200 km of natural gas pipelines for hydrogen transport and set up 100 km of new hydrogen pipelines connecting the Šaleška valley and the Zasavje region with Eastern Slovenia. In total, investments in hydrogen storage and transportation facilities would reach EUR 330M.

5.1.7 Batteries

The last technology I will consider are batteries. As will be explained in subchapter 5.3, I propose using in-front-of-the-meter battery systems with a power capacity of at least 5MW and behind-the-meter (BtM) battery systems with less than 5 MW. After electrolysers are added to the equation, the surplus (solar) power would still be present. These quantities can be covered by batteries, whose role would increase until 2035 and then gradually decrease as persistence of surplus solar power and presence of electrolysers would take off. That would also make economic sense as batteries are already a commercially relatively viable technology suited for deployment on a larger scale, whereas electrolysers still need to be further developed. Since excess solar power will occur for multiple hours on a sunny day, batteries energy capacities are of utmost importance. As the average ratio between energy capacity and installed power capacity of proposed batteries is more than 3.4 (see subchapter 5.3), it seems sensible to assume the availability factor of 0.6. The Table 34 shows battery storage systems' required installed power capacities and their energy capacities. For comparison, the scenario proposed by GEN-I (conversation with a GEN-I employee) envisions 500 MW, 1000 MW and 1,200 MW of batteries by 2030, 2035 and 2040, respectively, thus relatively in line with my estimates. Building upon the data from the subchapter 5.3, the total costs would amount to EUR 1,025M by 2040.

Table 34: Batteries from 2022 to 2040: installed power capacities and energy capacities

BATTERIES	2022	2025	2030	2035	2040
In-Front-of-the Meter (new) (MW)	8	85	235	385	410
Behind-the-Meter (new) (MW)	8	85	235	385	410
Total (existing + new) (MW)	45	200	500	800	850
Energy capacity IFotM (MWh)	31	353	976	1,599	1,703
Energy capacity BtM (MWh)	20	227	629	1,030	1,097
Total energy capacity (new + existing) (MWh)	81	610	1,635	2,659	2,830

Source: own work based on Lazard (2018).

5.1.8 Summary

To conclude, in 2040, excess power during the May Day holidays is expected to be covered by a combination of various technologies and approaches listed in Table 35, whose installed capacities will exceed the surplus power, enabling optimisation and adjustments to specific circumstances. The table also provides an overview of their energy storage capacities. In broad terms, the proposed options could be divided into three groups: long-term storage (electrolysers), short-term storage (PSHPPs, storage capacities of HPPs, batteries) and others (exports, demand-side management, disconnection of renewable energy power stations). During sunny periods, short-term storage technologies will play a minor role, whereas other appliances and approaches will be utilised to the maximum.

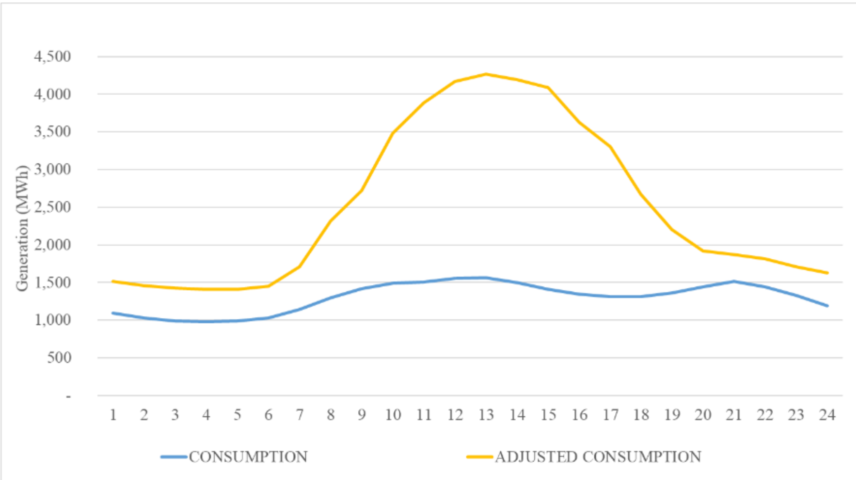
Table 35: Covering maximum surplus power output in 2040: installed power capacities of various technologies and their energy storage capacities

COVERING MAXIMUM SURPLUS POWER OUTPUT IN 2040	Installed power capacity (MW)	Energy storage capacity (MWh)
Total power	5,107	
Load	1,748	
Difference (power – load)	3,359	
Exports	400	continuously (if needed)
Demand side management	225	1,350MW per day (225MW for 5h, 112,5MW for 2h)
Electrolysers	1,550	continuously (if needed)
RES disconnection	-300	continuously (if needed)
Pumped storage hydropower	405	3,875
Storage capacity of existing HPPs	400	3,300
Battery storage	850	2,830

Source: own work.

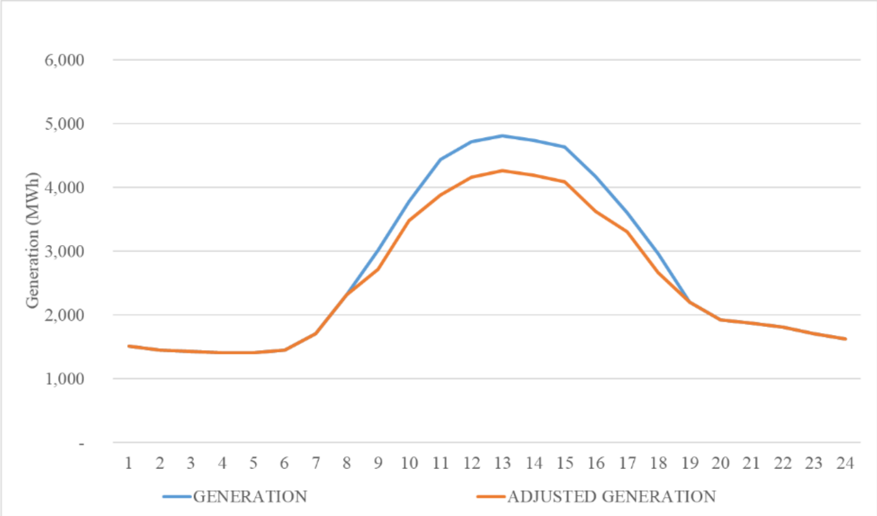
The two figures below are based on these assumptions and show consumption and adjusted consumption (Figure 18) as well as generation and adjusted generation (Figure 19) on a sunny day during the May Day holidays in 2040.

Figure 18: Consumption and adjusted consumption on a sunny day during the May Day holidays in 2040 (MWh)



Source: own work.

Figure 19: Generation and adjusted generation on a sunny day during the May Day holidays in 2040 (MWh)



Source: own work.

Cumulative investment costs for technologies and approaches identified above would amount to EUR 2,287M for the 2022–2040 period (Table 36). This calculation excludes the required investments into the distribution and transmission networks, since it is impossible to pinpoint what portion of the EUR 6,081M will be allocated exclusively to addressing surplus power. If this portion were included, the costs would increase. On the other hand, all of the expenses mentioned above cannot be objectively attributed solely to such a purpose either, as the technologies considered fulfil various functions in the electric power system. We must therefore be cautious when interpreting these results. Additionally, even though disconnecting RES from the grid does not incur expenses as such, it creates great opportunity costs.

Table 36: Inv. costs for covering max. excess power output from 2022 to 2040 (EUR M)

INVESTMENT COSTS FOR COVERING MAXIMUM EXCESS POWER OUTPUT (EUR M)	2022–2040
Exports	0
Demand side management	80
Pumped storage hydropower	383
Storage capacity of existing HPP	0
Electrolysers	469
Hydrogen transportation and storage facilities	330
RES disconnection	0
Battery storage	1,025
TOTAL	**2,287**

Source: own work.

5.2 Demand-side management

Demand-side management (DSM) "refers to initiatives and technologies that encourage consumers to optimise their energy use" (Energy Market Authority, n. d.) and has numerous benefits. The most important one, from the perspective of an energy system, is its disburdening of the electricity power system by shifting energy consumption from peak to non-peak hours. I have taken capacity and availability factors from the Consortium's scenario (conversation with ELES employees) and increased the capacity and summer availability factor by half, and the winter availability factor by a quarter (Table 37). As a working presumption, demand-side management providing full available capacity for five hours and half of its total potential for two hours per day has been assumed.

The arguments supporting such assumptions stem from various studies and policy proposals. First, one of SODO's main goals is to use demand-side management to reduce peak load on the distribution network by at least 10% by 2030 (Sistemski operater distribucijskega omrežja, 2020, p. 93). Second, a study conducted by Electrotechnical Institute Milan Vidmar for ELES concluded that peak load could be decreased by up to 300 MW by regulated and coordinated charging of electric vehicles alone (ELES, 2020, p. 81). Third, when ELES, Elektro Maribor and other actors collaborated on the NEDO project, they observed that households are prepared to substantially reduce their load in times of critical peak tariff, mostly during colder months, if appropriately compensated (Elektro Maribor, 2019). Fourth, the calculations made under the European project FutureFlow, coordinated by ELES, showed that in 2020, the total load-flexibility potential of industrial and commercial consumers in Austria, Slovenia, Hungary and Romania combined was 320 MW (iEnergija, n. d.). Through the market integration, such capacities could be made available to Slovenia as well. Lastly, a study for the U.S. market estimated that the "demand-side flexibility capacity of 20% of US peak load by 2030 would be cost-effective and could even be worth more than $15 billion annually in avoided system costs" (Smart Energy Europe, 2021, pp. 5). Similarly, the "European Commission found in its Impact Assessment for the European Clean Energy Package from 2016, that potential for Demand Response in Europe today is 100 GW, raising to 160 GW in 2030". Additionally, "avoided investments at distribution level thanks to the procurement of distributed flexibility can be of the order of up to €5 billion per year up to 2030" (Smart Energy Europe, 2021, p. 6).

The study Cost-Benefit Analysis of Advanced Metering in Slovenia (2014) estimated the investment costs for setting up an advanced metering system at EUR 60.4 M for the 2022–2025 period (investments already began in 2016) (Sistemski operater distribucijskega omrežja, 2016, p. 31). However, since the study did not include all aspects of the DSM (Sistemski operater distribucijskega omrežja, 2016, p. 13), I presume that an additional EUR 20M will be required. In total, EUR 80.4M would be needed to establish a fully operational demand-side management system in Slovenia, which translates into 53.6 EUR/kW, making DSM the most cost-effective solution considering investment costs. Table 37 provides an overview.

Table 37: Demand-side management from 2022 to 2040

DEMAND SIDE MANAGEMENT	2025	2030	2035	2040
CAPACITY (MW)	30	300	750	1,500
SUMMER AVAILABILITY FACTOR	0.15			
WINTER AVAILABILITY FACTOR	0.1875			
DAILY POTENTIAL	100% 5h; 50% 2h			
INV. COSTS (EUR/kW)	53.6			
TOTAL INVESTMENT COSTS (EUR M)	80.4			

Source: own work based on conversation with ELES employee; Sistemski operater distribucijskega omrežja (2016 and 2020); ELES (2020); Elektro Maribor (2019); iEnergija (n. d.); Smart Energy Europe (2021) and Lagler et al. (2014).

5.3 Batteries

Batteries have received much attention over the last few years. They provide aFRR, cope with excess solar power, enable a better overlap between the solar generation diagram and the diagram of household consumption, supply the electricity at the time of peak load, offset grid reinforcements and increase capacity factors of various renewable energy power plants (International Renewable Energy Agency, 2019). As has been underlined by Uroš Salobir (Klopčič, 2017) and Ervin Planinc (ELES, 2021c, p. 25), both from ELES, batteries are essential for providing aFRR in the future, especially for small markets like Slovenia. I took the battery classification from Lazard (2018, pp. 9–10) and considered three subtypes of both in-front-of-the-meter and behind-the-meter battery systems with different parameters (Table 38). My calculations are based on a capacity factor of roughly 0.1 and 90% efficiency (conversation with a GEN-I employee).

Table 38: Battery storage system: types, subtypes and other characteristics

Battery type and subtype		Lifetime (y)	Power Capacity (MW)	Energy Capacity (MWh)
In-Front-of-the-Meter	Wholesale	20	100	400
	Transmission and Distribution	20	10	60
	Utility-scale (PV + Storage)	20	20	80
Behind-the-Meter	Commercial & Industrial (Standalone)	10	1	2
	Commercial & Industrial (PV + Storage)	20	0.5	2
	Residential (PV + Storage)	20	0.01	0.04

Source: Lazard (2018).

The need for 500 MW of battery storage by 2030 and 800 MW by 2035 has already been explained above with an additional 10 MW per year from 2035 onwards. The outlined deployment also satisfies future aFRR requirements (subchapter 5.7) and adequately covers future peak load (subchapter 5.6). Behind-the-meter and in-front-of-the-meter batteries each covering half of the installed capacities are suggested. Such a division seems reasonable as behind-the-meter batteries would help various actors become (partially) self-sufficient, store energy for peak load, relieve the burden from the distribution network, reduce grid congestion and prevent some additional network investments, whereas in-front-of-the-meter batteries would make the transmission network more robust and significantly bring down the total investment costs. Table 39 summarizes the data.

Table 39: Batteries from 2022 to 2040: installed capacities, energy capacities, generation and consumption

BATTERIES	2022	2025	2030	2035	2040
In-Front-of-the Meter (new) (MW)	8	85	235	385	410
Behind-the-Meter (new) (MW)	8	85	235	385	410
Total (existing + new) (MW)	45	200	500	800	850
Energy capacity IFotM (MWh)	31	353	976	1,599	1,703
Energy capacity BtM (MWh)	20	227	629	1,030	1,097
Total energy capacity (new + existing) (MWh)	81	610	1,635	2,659	2,830
Generation (GWh)	40	179	448	716	761
Consumption (GWh)	45	199	497	796	845

Source: own work based on Lazard (2018) and conversation with a GEN-I employee.

The cost of batteries has dropped by 97% in the last three decades (Ritchie, 2021) and by 88% in the previous decade (Lee, 2020). To obtain investment costs for 2022, I took the average costs from Lazard for 2018 (2018, p. 13) and reduced them by 35%. I chose lithium batteries for in-front-of-the-meter batteries and lithium, lead and advanced lead batteries for behind-the-meter batteries. The relative reduction rate until 2050 was taken from Pietzcker, Osorio and Rodrigues (2021, p. 4). The current and future investment costs are summarized in Table 40.

Table 40: Investment costs for in-front-of-the-meter and behind-the-meter batteries from 2022 to 2040 (EUR/kW)

BATTERY INV. COSTS (EUR/kW)	2022	2025	2030	2035	2040
In-Front-of-the-Meter	1,150	1,058	905	752	599
Behind-the-Meter	1,994	1,834	1,569	1,304	1,038

Source: own work based on Lazard (2018) and Pietzcker, Osorio & Rodrigues (2021).

As seen from the Table 40, behind-the-meter batteries are expected to have significantly higher investment costs, additionally justifying my decision to give in-front-of-the-meter batteries an important future role. In total, building upon equation (2), roughly EUR 1,025M would be required to set up proposed battery capacities from 2022 to 2040 (Table 41).

Table 41: Total investment costs of in-front-of-the-meter and behind-the-meter batteries from 2022 to 2040 (EUR M)

INV. COSTS (EUR M)	2022	2023–25	2026–30	2031–35	2036–40	2022–40
In-Front-of-the-Meter	9	83	145	122	17	375
Behind-the-Meter	15	144	251	211	29	650
Total	24	227	396	333	45	1025

Source: own work.

5.4 Hydrogen and synthetic natural gas

Hydrogen, which has received much coverage recently, is produced by electrolysis of water, using electricity (and heat), in the electrolyser. Oxygen is the only by-product of the whole process. It presents one of the most promising paths to resolve seasonal imbalances generated by solar power plants because hydrogen can be stored in a natural or artificial environment during the warmer periods and utilised in power plants during the colder months. It can also provide the much-needed flexibility to the system, ancillary services, decarbonisation of hard-to-abate sectors through sector coupling, reduce the curtailment of renewable energy power plants and offset network upgrades. There are three methods to generate electricity with hydrogen: it can be used in fuel cells; it can be blended with natural gas and burned in upgraded gas turbines; or it can be combined with captured CO_2 and converted into SNG. Since the latter has the same characteristics as natural gas, it can be utilised in power plants without additional reconditioning.

5.4.1 Alkaline, polymer electrolyte membrane electrolysers or SOEC?

Electrolysers come in all sizes and shapes, but can be classified into different types depending on the nature of the electrolyte. The most promising electrolysers for near- to medium-term large-scale hydrogen production are alkaline electrolysers, polymer electrolyte membrane (PEM) electrolysers and solid oxide electrolyser cells (El-Emam & Özcan, 2019, p. 597), each of them with specific strengths and weaknesses. Alkaline electrolysers (El-Emam & Özcan, 2019, pp. 597–598) are the most mature, developed and widely used of all the electrolysers. They operate in the temperature range of 40–90°C and present a reliable and stable technology composed of non-noble materials. Even though they have a lower response time, they are cheaper than PEMs and can still significantly contribute to the reliability of ancillary services and the system as such. Their load can be ramped up and down by 0.2–20% per second (International Renewable Energy Agency, 2018, p. 23) and they can respond to a frequency dip of 0.2 Hz by reducing power consumption in less than a second (International Renewable Energy Agency, 2018, p. 123). The operational load of alkaline electrolysers ranges between 15% and 100% (International Renewable Energy Agency, 2018, p. 23). PEM electrolysers (El-Emam & Özcan, 2019, pp. 597–859), which are the second most mature of all electrolysers, operate at a temperature of 50–90°C and are more expensive than alkaline electrolyser, but can provide more ancillary services. Their load can be ramped up and down by 100% per second (International Renewable Energy Agency, 2018, p. 23) and they can respond to a frequency dip of 0.2 Hz by reducing power consumption in less than a second (International Renewable Energy Agency, 2018, p. 123). PEM electrolysers can operate for 10–30 minutes at up to 200% of their nominal load (International Renewable Energy Agency, 2018, p. 19). In contrast, SOECs (Koirala, 2020; Helmeth, n. d.; El-Emam & Özcan, 2019) are high-temperature electrolysers operating at temperatures within 650–1000°C. This technology is the least developed of all three and is expected to be proven in operation by 2030 (i.e. technology readiness level 9). In some aspects, however, SOECs are extraordinary. They are expected to incur lower capital costs than the other two types, they could be significantly more efficient (93%), function reversibly without compromising the performance (i.e. they could be used interchangeably as an electrolyser or a fuel cell)[19] and their response time is similar to that of PEM. What is more, they require less electricity due their high operating temperature and are therefore more profitable as heat is generally cheaper than electricity. On the other hand, the high operating temperature means that components deteriorate faster and, even more importantly, raises the question of how to provide adequate quantities of high-temperature heat sustainably. As medium and high-temperature nuclear reactors are not predicted to be commercially available in the near to medium future, five other options exist: biomass, which has been already considered and rejected (subchapter 4.4.2); waste heat, which is a viable option but only on a smaller and intermittent scale; geothermal energy, which can be potentially available in Eastern Slovenia but most likely at lower temperatures (see subchapter 4.6.2); electrical heating, which is an excessively costly option; and concentrated solar power, especially in the form of a solar power tower.[20] The latter seems the most promising choice for sustainably providing high-temperature heat on a medium scale. However, only a few studies have been conducted on this matter (e.g. Monnerie, Storch, Houaijia, Roeb & Sattler, 2017). In addition, a solar power tower is costly and has not experienced the same revival as solar power plants. It is therefore uncertain whether a SOEC, using heat from a solar power tower, can present an economically viable investment. This fundamental problem was also identified by IRENA, which has warned that “the need for high-temperature sources of heat close by might ... limit the long-term economic viability of SOEC” (International Renewable Energy Agency, 2018, p. 23). In light of these facts, I believe that PEM and alkaline electrolysers will be superior to SOEC ones at least until 2040.

5.4.2 Capacities, locations and investment costs of alkaline and polymer electrolyte membrane electrolysers

The exact share of alkaline and PEM electrolysers in the Slovenian decarbonisation plan has yet to be determined. However, as alkaline electrolysers cost less than PEM electrolysers (Table 43) and still have reasonable flexibility characteristics, I assume that three quarters of future installed capacities will be covered by alkaline electrolysers and the remainder by PEM electrolysers. Such a division will not compromise reliability of supply (see subchapters 5.7 on aFRR and 5.8 on mFRR).

According to the outlined decarbonisation plan, 1,163 MW of alkaline electrolysers and 388 MW of PEM electrolysers are to be constructed by 2040 in addition to the 220 MW alkaline electrolyser connected to JEK2. The deployment pace and installations per five-year period are presented in Table 42. Such a setting would reap the benefits of economies of scale,

19 In principle, the process of any fuel cell or electrolyser can be reversed due to the inherent reversibility of chemical reactions. However, most types are optimised to work efficiently only in one direction. SOEC, high-pressure electrolysers and some others are exceptions to this rule.

20 In theory, a SOEC could also operate without external high-temperature heat sources by using heat recovery or high-efficiency insulation, but such proposals seem implausible.

standardisation and future development as almost all objects would be set up after 2030, especially after 2035. Aside from JEK2, which will be built in Vrbina, half of the 1550 MW electrolysers will be located in the Zasavje region and another half in the Šaleška valley. All three energy locations present core Slovenian energy locations, where grid-related issues, siting and other challenges are the least demanding. Electrolysers located in the Šaleška valley will bring additional (green) development to the Šaleška valley, which will experience coal phase-out by the end of 2027. Even though (most) electrolysers cannot be included in the valley's restructuring plan due to the late start of their construction, the future installations can represent an additional argument in favour of the restructuring plan submitted to the EC. The Green Shine could partly finance these constructions and, in return, gain commensurate benefits during their operation. Even if the Green Shine did not participate in the building of electrolysers, restructuring plan would be essential as it would at least partly preserve energy location, energy knowledge and skilled workers. Regarding the Zasavje region, it is one of the poorest regions in Slovenia, with a formidable energy heritage, favourable network connections and abandoned energy locations waiting to be revitalised. It is also one of the two Slovenian regions being part of the EC's Initiative for Coal Regions in Transition.

Table 42: Alkaline and PEM electrolysers from 2022 to 2040 (MW)

ELECTROLYSER (MW)	2025	2030	2035	2040
Alkaline electrolyser	8	94	488	1,163
PEM electrolyser	3	31	163	388
Alkaline electrolyser at JEK2			220	220
TOTAL	**10**	**125**	**870**	**1,770**

Source: own work based on International Renewable Energy Agency (2018) and El-Emam & Özcan (2019).

Building upon IRENA's predictions for investment costs of utility-scale (roughly 50 MW) alkaline and PEM electrolysers for 2025 (2020, p. 72), Bloomberg NEF's forecasts on the capital costs of alkaline electrolysers for 2050 (2020, p. 5) and preserving the relative cost difference between the two for the whole observed period, future investment costs (EUR/kW) are presented in Table 43. IEA's Sustainable Development Scenario seems to confirm my assumptions, as its forecast for a generic hydrogen electrolyser is between my projections for an alkaline electrolyser and a PEM electrolyser.

Table 43: Investment costs of different electrolysers from 2022 to 2040 (EUR/kW).

INVESTMENT COSTS (EUR/kW)	2025	2030	2035	2040
Alkaline electrolyser	357	303	249	195
PEM electrolyser	447	379	312	244

Source: own work based on International Renewable Energy Agency (2020) and Bloomberg NEF (2020).

Building upon equation (2), cumulative investment costs for constructing 1,770 MW of electrolysers by 2040 would amount EUR 469M (Table 44).

Table 44: Total investment costs for constructing alkaline and PEM electrolysers from 2022 to 2040 (EUR M)

TOTAL INVESTMENT COSTS (EUR M)	2025	2026–2030	2031–2035	2036–2040	2021–2040
Alkaline electrolyser	3	28	107	146	284
PEM electrolyser	1	12	44	61	118
Alkaline electrolyser at JEK2			67		67
TOTAL	**4**	**40**	**218**	**207**	**469**

Source: own work.

Summarized data, disaggregated by type and location, is presented in Table 45.

Table 45: Electrolysers disaggregated by type and location and their total investment costs

ELECTROLYSERS	2040
Capacity (MW)	**1,770**
by site: in Vrbina/Krško	220
in the Zasavje region	775
in the Šaleška valley	775
by type: Alkaline electrolyser	1,383
PEM electrolyser	388
Investment costs (EUR M)	**469**
by type: Alkaline electrolyser	351
PEM electrolyser	118

Source: own work.

5.4.3 Economic viability of low-carbon hydrogen production and its cost price

At present, green hydrogen, produced by water electrolysis using carbon-free electricity, is not at price parity with grey hydrogen (El-Emam & Özcan, 2019, p. 605), generated from fossil fuels through steam reforming, for numerous reasons. Since the production of green hydrogen is still in the development or early-deployment stage, technologies and processes are not yet mature and standardized. When this technology is developed and deployed, costs will fall. In contrast, technologies related to grey hydrogen have been used for more than a century, are well matured and reach significant economies of scale. Importantly, grey hydrogen has competed on unequal terms with green hydrogen due to low or non-existent carbon prices. Since future carbon prices are expected to increase in the EU and worldwide, fossil fuel-based hydrogen production will have to internalize external costs and will thereby become less attractive. Additionally, many states have already adopted industrial policies, from subsidies to tax exemptions, stimulating the generation of low-carbon hydrogen (Huber, 2021).

There are five crucial factors determining the cost price and hence the economic viability of green hydrogen: capital expenditures, the utilisation rate of an electrolyser, its installed capacity, electricity price, and potential additional revenues. First, capital costs will decrease with additional funding for research and development, standardisation, accelerated deployment and progress along the learning curve (International Energy Agency, 2020, p. 420; see also Table 43). Second, hydrogen costs can be reduced with an increase in the utilisation rate of electrolysers. That would mean complementing electricity from SPPs with the electricity from other sources and the grid, thus spreading fixed costs over a higher quantity of hydrogen.[21] To be more precise, electrolyser's utilisation rates should be maintained somewhere between 50% and 80% to achieve economically viable production conditions at current investment costs. A nearly optimal level can be reached with an utilisation rate as low as 35% (International Renewable Energy Agency, 2019c, pp. 26–27). On the other hand, excessively high load factors can also be uneconomic. When they reach 80% or more, hydrogen cost prices soar due to expensive electricity (International Renewable Energy Agency, 2018, p. 25). Notably, the utilisation rates mentioned above and the very importance of the concept is going to gradually diminish as the prices of electrolysers and electricity decrease (in the medium term) and other factors come into play (International Renewable Energy Agency, 2018, p 29). Third, as electrolysis is an electricity-intensive chemical process and 70–90% of total hydrogen costs can be attributed to electricity (Bertuccioli et al., 2014, p. 30), securing a cost-effective source of electricity is of utmost importance. Nevertheless, as an adequately high utilisation rate significantly improves the economic performance of electrolysers, a balance needs to be struck between cheap electricity and an electrolyser's capacity factor. Fourth, size matters. IRENA predicts that an increase in electrolyser's capacity from 1 MW to 20 MW could reduce its costs by one third (Srnovšnik, 2020; International Renewable Energy Agency, 2020, p. 72). Last but not least, hydrogen costs can be further lowered by ancillary services-related revenues. To increase electrolyser's availability, it should be connected to the grid. Nonetheless, since

21 Higher capacity factors could also be reached by using energy storage technologies (e.g. pumped storage hydropower plants, batteries); however, these would increase the investments costs, making the project's economic viability questionable (El-Emam & Özcan, 2019, p. 606).

electrolysers will most likely be a part of a portfolio of a large energy group (e.g. GEN energija), they will not need to be available all the time.

My proposal regarding the deployment of electrolysers in Slovenia is in accord with the findings above and EC's Hydrogen Strategy for a Climate-neutral Europe (2020d). The latter predicts that electrolysers are going to reach maturity, become cost-competitive and be deployed *en masse* in the 2030–2050 period (2020d, p. 7). By constructing the facilities in line with the proposed timeline, we could reap the benefits of economies of scale, standardisation and future development. An adequate utilisation rate is expected to be achieved by using excess electricity from solar power stations (subchapter 5.1), off-peak electricity from the grid and electricity from hydropower plants and nuclear power plants in times of suboptimal market conditions. Notably, an overall decarbonisation of the electric power system will cause the decarbonisation of grid electricity, thus gradually decreasing the carbon intensity of hydrogen produced from grid electricity. Additionally, storage technologies (ČHE Avče, PČHE Rudar, batteries, storage capacities of HPPs etc.) could accumulate excess electricity and then provide it to electrolysers during the night or in other off-peak periods. The capacity factor of electrolysers connected to JEK2 is envisioned to reach 0.95, i.e. the same capacity factor as the power plant's (Naterer et al., 2013 in El-Emam & Özcan, 2019, p. 595), whereas the capacity factor of other electrolysers is predicted to attain 0.3 by 2033 and 0.45 from 2033 onwards. The average cost of electricity for non-JEK2 electrolysers is assumed to be 48 EUR/MWh throughout the observed period (correspondence with Mervar). The figure seems realistic as it is in line with or higher than the cost prices of solar and wind power plants (see chapter 6.3.1 on cost prices). In addition, with such an average, electrolysers can use more expensive electricity in some cases and cheaper electricity in others. Nevertheless, 48 EUR/MWh could also be somewhat inflated as the value is higher than the electricity cost in the worst-case scenario envisioned by Bloomberg NEF (Bloomberg NEF, 2020, pp. 2–3). Additionally, in the last few years, ČHE Avče bought electricity at a substantially lower price than 48/MWh (Soške elektrarne Nova Gorica, 2021, p. 27; Soške elektrarne Nova Gorica, 2020, p. 25; Soške elektrarne Nova Gorica, 2019, p. 25). However, as ČHE Avče has a capacity factor of 0.15 and proposed electrolysers 0.45, the comparison holds only partly. Finally, better coordination and joint projects with neighbouring countries with more optimal conditions for solar or wind power plants (Croatia, Austria, Italy, Western Balkans) could provide cheaper electricity too. The electricity cost for electrolyser directly connected to the JEK2 is assumed to be at the cost price of the power plant – 80 EUR/MWh (more in the subchapter 6.3.1 on cost prices).

Using the methodology, equations (6-9) and data presented in subchapter 6.3.1 on cost prices, I have calculated that JEK2 could generate hydrogen at the cost of 4.17 EUR/kg in 2040. That same year, it would provide roughly a fifth of domestically produced hydrogen, whereas other 1,550 MW electrolysers would cover the remaining part. Based on that same approach, the cost price of hydrogen produced in these electrolysers is estimated to reach 3.22 EUR/kg in 2030 and 2.57 EUR/kg in 2040. The weighted cost price of Slovenian hydrogen would thus amount to 3.22 EUR/kg in 2030 (produced in negligible quantities) and 2.93 EUR/kg in 2040. In 2040, with higher natural gas prices than in 2018 and the cost of carbon around 200 EUR/t (Pietzcker, Osorio & Rodrigues, 2021), hydrogen from coal without carbon capture, utilisation and storage (CCUS), coal with CCUS, natural gas without CCUS and natural gas with CCUS is expected to reach around 6.13 EUR/kg, 2.32 EUR/kg, 3.49 EUR/kg and 2.41 EUR/kg, respectively (International Energy Agency, 2019, p. 55). Thus, hydrogen costs obtained from proposed electrolysers using green electricity would be, in broad terms, cost comparable to other less climate-friendly sources. Notably, future hydrogen selling price is expected to be between 5 and 7 EUR/kg (Jovan and Dolanc, 2020, p. 4), thus making the proposed green production profitable. Table 46 summarizes the calculations. The cost of storage and transportation is not included in the calculations above (for this topic, see subchapter 5.4.5).

Table 46: Hydrogen cost prices from various electrolysers in 2030 and 2040 in comparison to cost prices from other sources and retail price (EUR/kg)

COST PRICE OF HYDROGEN (EUR/kg)	2030	2040
ELECTROLYSER AT JEK2		4.2
OTHER ELECTROLYSERS	3.2	2.6
WEIGHTED COST PRICE OF GREEN HYDROGEN	3.2	2.9
COAL WITHOUT CCUS	3.9	6.2
COAL WITH CCUS	2.1	2.3
NATURAL GAS WITHOUT CCUS	2.5	3.5
NATURAL GAS WITH CCUS	2.2	2.4
RETAIL PRICE	5–7	5–7

Source: own work based on Jovan and Dolanc (2020); correspondence with Mervar; Fürstenwerth (2014) and International Energy Agency (2019).

5.4.4 Quantity of hydrogen produced

I will now attempt to estimate the quantity of hydrogen produced by the proposed electrolysers using the equation (4). Electrolyser efficiency, measured in kWh of electricity used per kg of hydrogen generated, has been calculated based on IRENA's estimated efficiency of 51 kWh/kgH_2 in 2025 and a linear reduction rate of roughly 4 kWh/kgH_2 per 8 years (2018, p. 20). Capacity factors of 0.95 for the electrolyser connected to JEK2 and 0.3 (until 2033) or 0.45 (from 2033 onwards) for all other electrolysers are expected. In total, building upon equation (4), electrolysers will consume 7.95 TWh of electricity in 2040, and total hydrogen production will equal 177 kt or 2,078 million m^3 at 15°C and 1 bar in 2040. For comparison, natural gas consumption was 937 million m^3 at 15°C and 1 bar in 2020 and the NECP's nuclear scenario estimate the demand for gaseous fuels (i.e. natural gas, hydrogen, SNG, etc.) to reach 1,171 million m^3 in 2040 (Portal Energetika, 2019).

$$H_2generated_{t,tech-e} = \frac{MW_{tech-e,t} * capacity\ factor_{t,tech-e} * 1000 * 8765}{efficiency_{t,tech-e}} \tag{4}$$

$H_2generated_{t,tech-e}$ = quantity of hydrogen generated by a specific type of electrolyser in year t (kg–H_2)

Capacity $factor_{t,tech-e}$ = capacity factor of a specific type of electrolyser in year t

$MW_{t.tech-e}$ = installed capacity of a specific type of electrolyser in year t (MW)

$Efficiency_{t,tech-e}$ = amount of electricity that a specific type of electrolyser consumes to produce one kilogram of hydrogen in year t (kWh/kg-H_2)

8765 = number of hours in one mean calendar year

In volumetric terms, hydrogen will be thus produced at almost twice the volume, but the picture is somewhat different when comparing the gross heating value of both sources. The gross heating value (MJ/m^3) of hydrogen is roughly one third of the gross heating value of natural gas (Engineering ToolBox, 2008), meaning that the total available energy content of hydrogen will be 27 PJ in 2040, whereas the total demand for gaseous fuels will top 39 PJ. In calorific values, domestic hydrogen is thus expected to cover 67% of the total demand. As the production of SNG, where hydrogen is combined with CO_2, entails additional steps and transformations, reducing the energy content even further, it should be a priority to consume hydrogen directly and not converse it into SNG (Babič, 2021). Encouragingly, companies are already developing gas-fired OCGTs, which can be upgraded to operate on high hydrogen fuel or even exclusively on hydrogen (Goldmeer, 2019). Fuel cells could also be used as an alternative or complement to H_2-fired OCGTs. However, based on the specific hydrogen characteristics (low heating value, high flame velocity, low luminosity, high diffusability, higher flammability (Goldmeer, 2019)) and the need to upgrade the broader gas infrastructure in case of only hydrogen is intended to be used, hydrogen entirely substituting natural gas does not seem a tenable and realistic proposition. Future development will determine whether in these instances natural gas will be decarbonised by using SNG or capturing GHG emissions from the burning of natural gas. For now, the latter option seems more sensible, at least until 2050 (Babič, 2021). However, producing a certain amount of SNG nevertheless appears highly likely. I thus assume that one third of total hydrogen will be converted into SNG, and since during this process half of the hydrogen is lost as water (Babič, 2021), the combined energy contents of hydrogen and SNG will entail 21.9 PJ. In 2040, domestically generated hydrogen and its derivatives would therefore cover 56% of the demand for gaseous fuels[22], while the remainder shall be imported to achieve society-wide decarbonisation (i.e. not only in the electric power system). As hydrogen

22 Such statements should be made with a certain degree of caution, as downstream processes and transformations have not been included in the calculation. It seems plausible that hydrogen-fired technologies will be slightly more efficient than natural gas-fired technologies, furthering the increase in the hydrogen's value.

initiatives and projects in the North Sea, Africa and other locations are rapidly evolving (European Commission, 2020d, p. 2; Africa–EU Energy Partnership, 2020), such a proposition seems realistic and also economically reasonable, as the production conditions in these areas are better than in Slovenia. The data is summarized in Table 47.

Table 47: Hydrogen and synthetic natural gas: domestic production and coverage of gaseous fuel consumption in 2040

HYDROGEN AND SYNTHETIC NATURAL GAS	2040
H_2 produced by the electrolyser at JEK2 (kt)	40
H_2 produced by other electrolysers (kt)	137
Total H_2 production (kt)	177
Total electricity consumption (GWh)	7,945
Volume of hydrogen available at 15°C and 1 bar (million m^3)	2,078
Consumption of gaseous fuels in 2020 (million m^3)	937
Consumption of gaseous fuels in 2040 (million m^3)	1,171
H_2:gaseous fuels volume ratio	1.8
H_2 gross heating value, volume terms (MJ/m^3)	12.8
Natural gas gross heating value, volume terms (MJ/m^3)	40.5
H_2:CH_4 energy content ratio	0.32
Total H_2 energy content available (PJ)	26.6
Total gaseous fuels energy content required (PJ)	39.5
Domestic H_2 as a share of gaseous fuels consumption in 2040	0.67
Total H_2 and SNG energy content available (PJ)	21.9
Domestic H_2 & SNG as a share of gaseous fuels consumption in 2040	0.56

Source: own work based on Engineering ToolBox (2008) and Portal Energetika (2019).

The pace at which domestic hydrogen and SNG will replace natural gas in the electric power system and CHP plants was calculated using equation (5) and based on the assumptions presented above and an efficiency rate of 55% for 2025 and 60% for 2040 for hydrogen-based power plants. The latter two values present a weighted efficiency of proposed OCGTs, CCGTs and CHP plants. Full-cycle efficiency (i.e. electricity–hydrogen and SNG–electricity) is estimated to reach 31% in 2025 and 40% in 2040. Such a value is lower than 35–50% envisioned by ELES and GEN-I, which means that my assumption is more conservative. However, if their presumption is correct, in my scenario less electricity would be consumed for the same amount of electricity produced or more electricity would be generated with the same amount of input electricity, making the scenario even more promising.

$$\begin{aligned} Electricity\ produced\ by\ power\ plants\ using\ H_2\ and\ SNG_t \\ = \left(x * H_2 generated_t + (1-x) * H_2 generated_t \right. \\ \left. * SNG\ transformation\right) * H_2\ usable\ energy * efficiency_{t,tech-p} \end{aligned} \quad (5)$$

Electricity produced by power plants using H_2 and SNG_t = electricity produced in various power plants by using hydrogen and synthetic natural gas as a fuel (KWh)

x = share of hydrogen generated not transformed into synthetic natural gas (%)

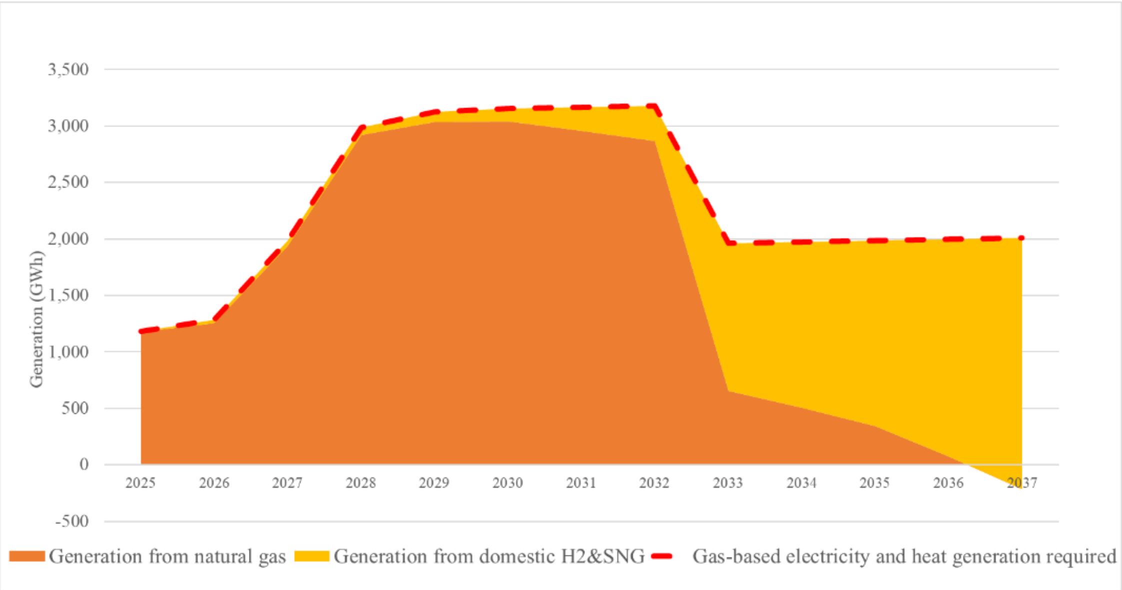
SNG transformation = share of usable hydrogen remained after the conversion into synthetic natural gas (%)

H_2 usable energy = amount of usable energy in one kilogram of hydrogen (KWh/kg)

$Efficiency_{t,tech-p}$ = ratio of a unit of energy obtained against the number of equivalent units of energy a power plant requires to produce it in year t (%)

Next, the available electricity generated from domestic hydrogen and SNG was juxtaposed to the required gas-based electricity (i.e. production in OCGTs, CCGTs and CHPs). As shown in Figure 20, domestic hydrogen and SNG, used exclusively for electricity and heat generation, are expected to substitute natural gas in the electric power system and CHP-part of the heating sector entirely by around 2036, making gas-based electricity and part of the heat production low- or zero-carbon.

Figure 20: Gas-based production of electricity and heat in the electric power system and CHP part of the heating sector: role of hydrogen and synthetic natural gas (GWh)



Source: own work.

5.4.5 Hydrogen storage and transportation

At present, there are no natural gas or hydrogen storage facilities in Slovenia. In comparison to the relatively well-studied technical and economic perspectives of hydrogen generation covered above, storage has thus far received much less attention for three reasons. First, hydrogen production as a solution for intermittent renewable energy power plants has come to the forefront only in the last few years and presents enough other challenges as is. Second, hydrogen can be infused into the gas network, which can contain and secure a 10–20% share of hydrogen in volumetric terms without significant upgrades (International Renewable Energy Agency, 2019, p. 19). After appropriate upgrades, the gas network can uptake a higher share of hydrogen (Trouvé et al., 2019). Third, seasonal storage is unnecessary if hydrogen is consumed by the industrial, chemical, agricultural, heavy transport and other sectors throughout the year. These have their own, primarily short-term storage systems or use hydrogen instantly, and do not require much long-term storage. As the hydrogen economy grows, more and more actors will consume hydrogen. However, the projected hydrogen production during the warmer months of the late 2030s would almost certainly outpace the immediate and near-term Slovenian needs, especially since hydrogen is considerably larger in volume than natural gas. In addition, as we have already seen with the excess electricity from SPPs, it would be highly optimistic to expect that in the summer the entire hydrogen production would be exported, whereas in the winter the total hydrogen required would be imported. Therefore, it seems reasonable to assume that in about 2040, Slovenia will export a part of the surplus quantities of hydrogen and store the remaining share. As an electrolyser connected to JEK2 will continuously provide roughly one-quarter of hydrogen throughout the year, storage facilities will not be required. I presume that the second quarter will be exported and the third one consumed instantly or in the near term. Storage facilities would thus only be required for the last quarter (i.e. 44.2 kt). Where to deposit such a quantity remains to be decisively answered, as no thorough studies on this matter have yet been conducted (conversation with dr. Miloš Markič). However, in the following part, a preliminary assessment of Slovenia's potential hydrogen storage sites will be given.

In theory, there are several options for monthly and seasonal storage, including salt caverns, depleted gas reservoirs, rock caverns, ammonia and liquid organic hydrogen carriers, but in general it is cheaper to deposit hydrogen in existing rock formations than to use alternative storage technologies (Bloomberg NEF, 2020, p. 3). Moreover, road or maritime transportation is expensive (Bloomberg NEF, 2020, p. 4), making hydrogen production, storage and usage in a single location economically sensible. Since there are no salt caverns appropriate for hydrogen storage in Slovenia (Caglayan et al., 2020), the two most suitable alternatives are presumably the depleted natural gas reservoirs in Eastern Slovenia and the rock caverns under the Šaleška valley.

In the Šaleška valley, hydrogen storage facilities could make use of the already excavated hollows, lowering the construction costs. Additionally, as roughly half of the hydrogen would be generated in Šaleška valley (see subchapter 5.4.2), transportation costs would be reduced or eliminated. Additionally, underground water located around PV or abundant surface water from artificial lakes could be used in the process of sealing the rock or applying a water curtain (Papadias & Ahluwalia, 2021, p. 34528). Zivar, Kumar and Foroozesh have also underlined the future potential of abandoned coal mines as hydrogen storage sites (2021, p. 23439). On the other hand, since the terrain is unstable and the underground structure might need to be sealed, coated and fortified, the question of (un)permeability and existing fractures and fissures must be considered (conversation with dr. Miloš Markič; Papadias & Ahluwalia, 2021, p. 34528). As researchers from the Geological Survey of Slovenia have declared the geological formations beneath the Šaleška valley as potentially unsuitable for carbon storage (conversation with dr. Miloš Markič), it seems probable that a hydrogen depository will also be deemed unacceptable. Moreover, if the coated and fortified tunnels of PV were used, the reservoir's capacity would amount to 500,000–780,000 m^3 with a pressure of up to 50 bar and temperature of 30°C (conversation with dr. Miloš Markič), making the storage site immensely insufficient to deposit the proposed 44.2 kt of hydrogen. The conditions at PV could be sufficiently improved by lowering the temperature of hydrogen to as much as –250°C and keeping the pressure unchanged (conversation with dr. Miloš Markič); however, liquefaction is costly and energy-consuming (Papadias & Ahluwalia, 2021, p. 34528), rendering the Šaleška valley an even less attractive option.

The second potential depository area are the Petišovci, Paka, Ratka and Lovaszi depleted natural gas reservoirs, all located in Eastern Slovenia at a depth of 1,000–2,000 m, with a temperature of 60–80°C and pressure of 120–160 bar (conversation with dr. Miloš Markič). The on-site pressure is significantly higher than in the Šaleška valley, reducing the storage volume requirements, enabling significantly higher temperatures than in PV and contributing to lower investment and operational costs. Under these conditions, approximately 15 kt or one third of the desired quantity of hydrogen could be stored (conversation with dr. Miloš Markič). By only moderately adjusting these conditions (i.e. somewhat lower temperatures or/and higher pressure), the depleted natural gas and oil reservoirs in Eastern Slovenia would presumably become the most appropriate hydrogen depository. Zivar, Kumar and Foroozesh (2021, p. 23455) and Lord, Kobos and Borns (2014) arrived at a similar conclusion. Envisioned for 2040, the proposed storage facility is comparable to the existing hydrogen storage locations throughout the world (Zivar, Kumar & Foroozesh, 2021, pp. 23441–23443). However, these briefly outlined options are only a preliminary assessment. For more accurate results, multiple interdisciplinary studies should be conducted. In this respect, the studies on the availability of carbon capture and storage in Slovenia, published in eight books, can offer an important reference point (Markič, 2020).

Lord, Kobos and Borns (2014, pp. 15574–15575) estimated the investment costs for converting a depleted oil and gas reservoir with similar characteristics as those in Eastern Slovenia into a hydrogen storage site. At 41.85°C and 137.55 bars, a depository size of 2,868 t-H_2 would cost roughly EUR 34M or 11.9 EUR/H_2-stored. Dividing these costs by half due to future development (Bloomberg NEF, 2020, p. 3) and further reducing them for one third due to economies of scale,[23] capital costs for the 2035–2040 period would amount to 3.92 EUR/kg-H_2. The construction of a reservoir with a capacity of 44.16 kt-H_2 would thus cost EUR 182M in 2040. As a consequence of choosing Eastern Slovenian for a hydrogen storage site, the need for hydrogen transportation arises.

The hydrogen generated in the Zasavje region and the Šaleška valley is predicted to be transported to Eastern Slovenia through bi-directional newly constructed hydrogen and repurposed natural gas pipelines with a total length of 300 km. Currently, the cost of repurposing a natural gas pipeline into a hydrogen pipeline is EUR 0.4M per kilometre (Agency For The Cooperation Of Energy Regulators, 2021, p. 13), while the cost of constructing a new hydrogen pipeline is EUR 2.2M on average (Agency For The Cooperation Of Energy Regulators, 2021, p. 13). Assuming a cost reduction of 50% due to future development, building 100 km of new pipelines and repurposing the remaining 200 km of old pipelines would cost EUR 148M from 2034 to 2040. In total, hydrogen storage and transportation expenses would total EUR 330M by 2040. For sake of comparison, applying optimistic assumptions (e.g. 75 not 50 bar, no excavations costs) and investments costs presented by Papadias and Ahluwalia (2021, p. 34535), storage and transportation costs in the Šaleška valley would equal EUR 403M. Therefore, also from the economic point of view, the Petišovci, Paka, Ratka and Lovaszi depleted gas and oil reservoirs seem a more sensible choice than the Šaleška valley. Table 48 provides a summary of my calculations.

Table 48: Hydrogen storage and transportation facilities by 2040

HYDROGEN STORAGE AND TRANSPORTATION	2040
STORAGE INV. COSTS (EUR/kg-H_2)	4.12
SIZE (kg-H_2)	44,155,441
TOTAL STORAGE INV. COSTS (EUR M)	182
REPURPOSING NATURAL GAS PIPELINES (EUR M/km)	0.2
LENGTH (km)	200
NEW HYDROGEN PIPELINES (EUR M/km)	1.1
LENGTH (km)	100
TRANSPORTATION COSTS (EUR M)	148
TOTAL STORAGE&TRANSPORTATION COSTS (EUR M)	**330**

Source: own work based on Agency for the Cooperation of Energy Regulators (2021) and Lord, Kobos & Brons (2014).

What do storage and transportation costs mean for the hydrogen cost price? Based on the findings by Bloomberg NEF (2020, p. 5), I assume transportation and storage costs would

23 A 72.5% cost reduction can be achieved by scaling storage from 100 t-H2 to 3,000 t-H2 (Papadias & Ahluwalia, 2021, pp. 34538–34539).

increase hydrogen price by 10%. This increment will be included in the calculations on the electricity cost price of various power plants in the subchapter 6.3.1.

5.5 Strategic reserves

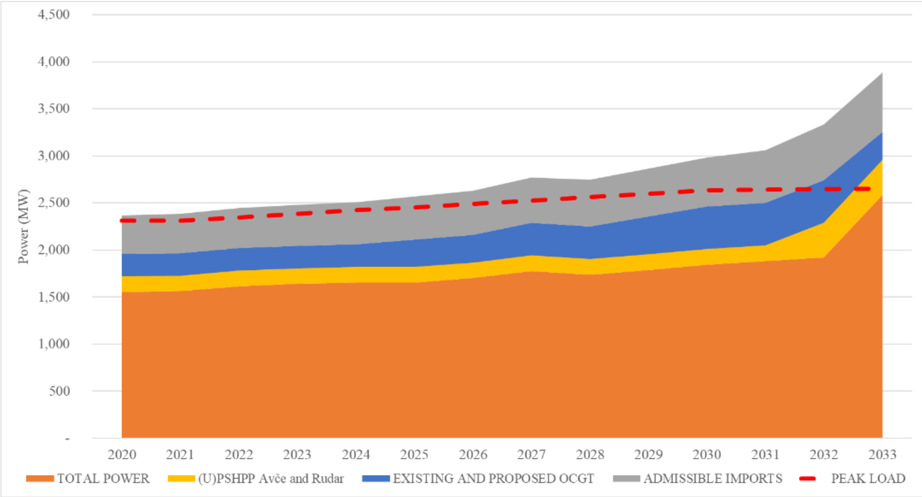
5.5.1 Strategic reserves, their role and installed capacities

The general tendency in electricity generation is towards smaller, distributed power stations using unstable energy sources highly dependent on various natural factors. For such reasons, renewable energy power plants have a lower capacity factor than other power stations (except potentially offshore WPPs, which are irrelevant for Slovenia). In 2019, the (assumed) capacity factors in the EU were 75% for NPPs, 40% for coal and gas-fired CCGTs, 28% for onshore WPPs and 13% for SPPs (International Energy Agency, 2020, p. 419). Even more fundamentally, the generation provided by such plants is intermittent and prone to rapid fluctuations, underlying the need for flexible and fast-responsive plants that would operate independently from natural circumstances. Additionally, future challenges and problems will magnify due to coal and, in some countries, nuclear phase-out and low prices on the wholesale electricity market, frequently driven by subsidised and preferentially-dispatched electricity from renewable energy power plants. The latter makes investments into new power plants and the operation of old, amortised facilities with high operation costs uneconomic. In the future, Europe will therefore experience problems with the adequacy and security of electricity supply if nothing is done to counteract these trends (Medved, Bajec Omahen, Pantoš & Gubina, 2015; Mervar, 2014, pp. 108–114; Volfrand, 2021). An essential part of the solution for coping with such developments are strategic reserves. They represent flexible, fast-responsive power plants, especially OCGTs, providing adequate supply when required. These newly constructed or preserved power plants are started only in difficult times. “These emergencies are generally defined as an event where the electricity prices on the day-ahead market, intra-day market or balancing market increase above some predefined level.” (Mervar, 2014, p. 110) At present, the construction of new and preservation of old strategic reserves is uneconomic (Volfrand, 2021), underlying the need for the state to step in, and it has already been proposed that capacity remuneration mechanisms (CRM) should be used to stimulate the construction of such facilities (Medved et a., 2015; Mervar, 2014, pp. 108–114). The legal base for the implementation of CRM was included in the draft of the amended Electricity Supply Act (2020, pp. 54–57), approved by the Slovenian government in June 2021. “An independent authority, typically a system operator, determines the scope of the reserves and dispatches them when needed. Lease of reserves is mainly managed on an annual basis, whereas additional costs … are of course mirrored in the increase of the final price and are borne by the network user” (Mervar, 2014, p. 110). In the past, CRM was mainly used for ensuring sufficient generating capacities during peak load times, but nowadays they also assure the security of supply due to intermittent electricity generation from variable renewable energy power plants (Mervar, 2014, pp. 109–110). To sum up, strategic reserves fall under the realm of security of supply and are constructed and managed by energy suppliers, (mostly) dispatched by the transmission system operator and shaped by ministry officials (and politicians), who define their construction and operation conditions.

I propose setting up four 53 MW of OCGTs by 2030, totalling 212 MW. Three of them would be built in Brestanica (in 2025, 2027 and 2030), as TEB has already obtained the construction permits for blocks 8 and 9 (Stanković, 2021), and one in Šaleška valley (in 2029; alongside 114 MW of CCGT). Since all necessary steps to bring investment in OCGT to an end take roughly 2–3 years if an already existing energy site is utilised (appointment with TEB employee), constructing four OCGTs in two well-established energy locations by the end of 2030 is feasible. Such a proposal will be assessed in two ways. The first approach relates to the winter months, and the second to the summer period.

To estimate the sensibility of the total installed capacity proposed above, I have taken the average power output of power plants during peak load times, the available output of batteries and (P)ČHE Avče and Rudar, admissible imports and the existing and proposed strategic reserves, and then subtracted these values from the projected peak load (correspondence with Mervar). To obtain average capacity factors, I took the period between 8:00 and 11:00 and between 18:00 and 20:00 in January 2019–2021. Since the capacities of Slovenian WPPs are insufficient to achieve firm results, I have used the data for Austria from the ENTSO-E database. The average peak load capacity factor of CCGTs was obtained from the average peak load capacity factor of TEŠ (0.71). The effective power output of various batteries and ČHE Avče was estimated at the availability factor of 0.3 and 0.9, respectively. For admissible and realistically envisioned imports not posing an excessive threat to the security of supply, I have used the quarter of the annual electricity consumption, recalculated on an hourly basis, defined in the NECP (Žerdin et al., 2021, p. 195). Finally, the existing strategic reserves include the OCGTs in TEB and TEŠ. Regarding TEB, I took into account the entire fleet of seven gas turbines as decommissioning of the first three blocks could be postponed until the next decade if needed due to the future conditions on the electric power system, which is what TEB expects will happen (conversation with a TEB employee). I, therefore, assume that one to three TEB's gas turbines will be decommissioned in 2033 and that no additional shutdowns will occur by 2040. As for TEŠ, I presume the postponement of the shutdown of both gas turbines from 2027, as it is currently planned, to at least 2033. The postponement is technically feasible (conversation with a TEŠ employee), even more so as both power stations are younger than most of the gas-fired fleet in TEB. However, as 250 MW of OCGTs in TEB are devoted to providing mFRR and cannot serve as strategic reserves, the existing strategic reserves amount to 240 MW and 87 MW until 2033 and during 2033–2040, respectively. As seen in Figure 21, existing and proposed strategic reserves would ensure that less than admissible imports would be required to cover the peak load, making the system more robust. From 2032 onwards, imports would not be needed.

Figure 21: Evolution and role of strategic reserves in covering peak load by 2033 (MW)

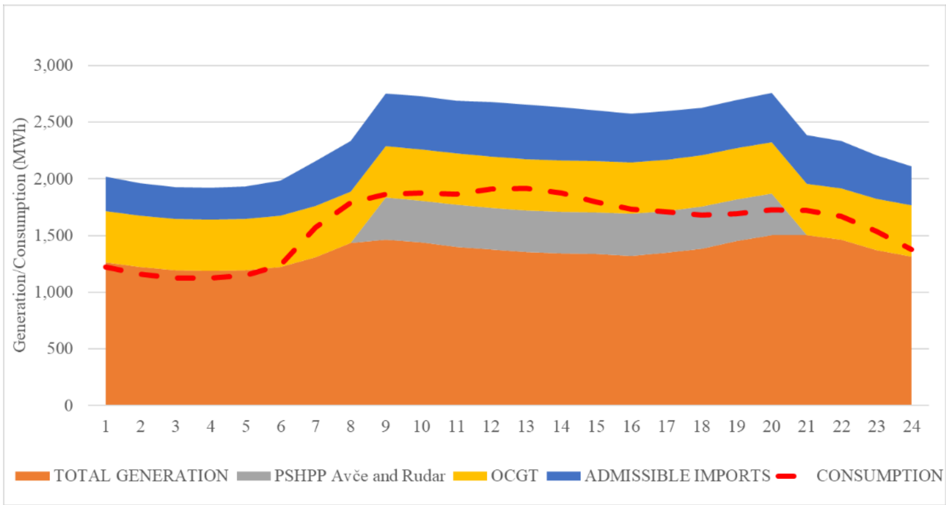


Source: own work based on ENTSO-E; correspondence with Mervar; Žerdin et al. (2021); conversation with a TEB employee and conversation with a TEŠ employee.

The second essential function of strategic reserves is to provide flexibility in times of sudden and abrupt fluctuations in electricity generated by renewable energy power plants. This aspect will be assessed by looking at the role of OCGTs in 2032, one year before JEK2 and the electrolyser linked to JEK2 will be connected to the grid, and the role of OCGTs in 2040, when the effects of SPPs deployment on other power stations will be the largest.

Regarding the first case, the sensibility of the proposed capacity of strategic reserves was assessed by combing the average power output of various power plants in June excluding SPPs and WPPs (i.e. 0 MW of output power), the available power output of batteries, (P)ČHE Avče and Rudar, the strategic reserves and the admissible imports, and then subtracting this amount from the average consumption on working days in June 2032. I chose the working days of June because consumption is higher than in July and at weekends and the effects of air conditioning are already considerable, and generation from conventional power plants is lower than in most of the other months due to a generally higher production from renewable energy power plants. I took the availability factors of 0.9 and 0.3 for (U)PSHPPs and battery storage systems, respectively, and assumed that the power output of HPPs will decrease by 5% due to climate change (Agencija Republike Slovenije za okolje, 2018, pp. 39, 144). Admissible imports were devised in the same manner as in the first approach. Figure 22 shows the obtained results by scaling the data from ELES and Borzen to 2032. As can be seen, even without imports and demand-side management, strategic reserves and power plants, excluding SPPs and WPPs, would be able to cover hourly load on a hypothetical working day without sun and wind in June 2032. Importantly, in terms of imports, the potential earlier closure of one to three gas turbines in TEB and both gas turbines in TEŠ would not threaten security and adequacy of supply.

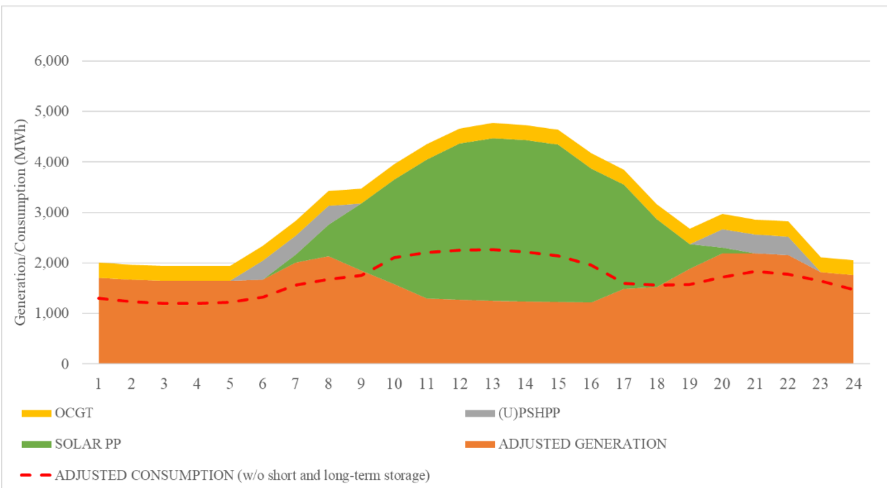
Figure 22: Daily diagram for June 2032 without solar and wind PPs (MWh)



Source: own work.

The second instance concerning the summer role of OCGTs relates to the summer evenings, when the power output of SPPs rapidly decreases, demand is still high, rendering the case for flexible power plants to step in. Building upon the proposed deployment of different power plants and taking the average capacity factor of the fifth of the sunniest June days during 2018–2020, Figure 23 is obtained. As can be observed, power stations (excluding SPPs) would provide enough power output in a flexible way (i.e. fewer exports, fewer RES disconnections, less electricity powering the electrolyser linked to JEK2) to replace the receding production from SPPs and meet the evening demand (excluding short- and long-term storage). Demand-side management would also play an important role in shifting the load from morning and evening to noon and afternoon. OCGTs and (U)PSHPPs would thus generally not be used but would provide a backup.

Figure 23: Daily diagram for June 2040 with solar and wind PPs (MWh)



Source: own work.

In total, strategic reserves would gradually increase from the existing 240 MW to 346 MW in 2028 and 452 MW in 2030 and remain at that level until 2033. From 2033 onwards, their capacity would decrease to 299 MW due to shutdowns. Table 49 provides a summary.

Table 49: Deployment of strategic reserves (OCGTs) from 2022 to 2040 (MW)

OCGTs – STRATEGIC RESERVES	2021	2025	2028	2030	2035	2040
NEW OCGTs (MW)	0	53	106	212	212	212
EXISTING OCGTs (MW)	240	240	240	240	87	87
TOTAL (MW)	**240**	**293**	**346**	**452**	**299**	**299**

Source: own work.

5.5.2 Investments costs, electricity generation and refurbishment of OCGTs, CCGTs and CHP plants to become hydrogen-capable

The envisioned OCGTs would encompass four open-cycle gas turbines with an installed capacity of 53 MW each, thus similar to the Siemens SGT-800 gas turbine in blocks 6 and 7 in Brestanica, totalling 212 MW. Since natural gas is a fossil fuel, it should be replaced or decarbonised. There are four main options to achieve this objective. First, domestic (and/or imported) hydrogen could be used in fuel-flexible or entirely hydrogen-based power plants. Research, development and usage of such technologies have been steadily rising (Goldmeer, 2019; Patel, 2020). For example, Siemens, providing gas turbines also to TEB, has pledged to make all its gas turbines entirely hydrogen-capable by 2030 (Patel, 2020). The SGT-800, used in blocks 6 and 7 in TEB, can already run on fuel containing up to 75% of hydrogen by volume with a DLE burner (Siemens energy, n. d.). Nevertheless, the higher the share of hydrogen in blended fuel, the higher the adaptation costs of the whole gas turbine system (Goldmeer, 2019, p. 15). Second, if it turns out that upgrading the entire system to run exclusively on hydrogen until at least 2040 is excessively costly, hydrogen could be combined with CO_2 and converted into synthetic natural gas. In this case, gas turbines would not need to be refurbished, but the efficiency of the whole process would decrease due to additional chemical reactions. With such a development in mind, I estimated that one third of domestically produced hydrogen would be converted into SNG (subchapter 5.4). Third, if fuel cells developed quickly enough (International Energy Agency, 2020, p. 420), they could gradually replace hydrogen-fired OCGTs and CCGTs as the principal hydrogen consumers for electricity generation. Last but not least, carbon could be captured from gas-fired power plants and stored underground. Still, to make such investments reasonable, various technical and especially economic questions have to be resolved first (European Commission, n d. d.). It is too early to define the exact decarbonisation path of strategic reserves, but if I am to calculate the total costs of the decarbonisation plan, I need a working hypothesis. To that end, I envision converting one third of future hydrogen into SNG and upgrading remaining gas-fired OCGTs, CCGTs and CHP plants into hydrogen-based power plants.

Taking the average investment costs (EUR/kW) for gas- and hydrogen-fired OCGTs (Pietzcker, Osorio & Rodrigues, 2021, p. 3) and block 7 of TEB (P. P., 2021) and using equation (2), total capital costs for setting up OCGTs would amount to EUR 91M by 2030 (Table 50).

Table 50: Total investment costs of new strategic reserves by 2040

NEW OCGTs – STRATEGIC RESERVES	2030
INV. COSTS (EUR/kW)	430
CAPACITY (MW)	212
TOTAL COSTS (EUR M)	91

Source: own work based on Pietzcker, Osorio & Rodrigues (2021) and P. P. (2021).

I have predicted that additional refurbishments and upgrades of gas-fired systems would amount to one third of the initial investment costs (Goldmeer, 2019, p. 15) and unfold from 2033 to 2038, in which case they would reach EUR 29M (Table 51). The same approach was applied to CHP power plants and CCGTs. Note that one third of hydrogen produced would be converted to SNG, not requiring additional upgrades of power plants. In total, EUR 148M would be required to upgrade power plants to become entirely hydrogen-based.

Table 51: Total investment costs of upgrading OCGTs, CHP plants and CCGTs to run exclusively on hydrogen

UPGRADING TO ENTIRELY H2-FIRED POWER PLANT	2033-2038
OCGT REFURBISHMENT COSTS (EUR/kW)	143
EFFECTIVE CAPACITY (MW)	199
TOTAL INV. COSTS (EUR M)	29
CHPP REFURBISHMENT COSTS (EUR/kW)	558
EFFECTIVE CAPACITY (MW)	113
TOTAL INV. COSTS (EUR M)	63
CCGT REFURBISHMENT COSTS (EUR/kW)	298
EFFECTIVE CAPACITY (MW)	190
TOTAL INV. COSTS (EUR M)	57
TOTAL INV. COSTS - SUM (EUR M)	**148**

Source: own work based on Goldmeer (2019).

Electricity generation of existing and new OCGTs until 2040 has been calculated based on the equation (3) and capacity factor of 0.025 for 2021 (Termoelektrarna Šoštanj), 0.25 from 2028 until including 2032 and 0.1 from 2033 onwards, reasonably low due to their inferior efficiency (see also EC, 2020e, p. 43). The results are shown in the Table 52.

Table 52: Installed capacities and electricity generation from strategic reserves from 2021 to 2040

OCGTs – STRATEGIC RESERVES	2021	2025	2028	2030	2035	2040
NEW OCGTs (MW)	0	53	106	212	212	212
EXISTING OCGTs (MW)	240	240	240	240	87	87
TOTAL (MW)	240	293	346	452	299	299
GENERATION (GWh)	53	394	758	990	262	262

Source: own work based on Termoelektrarna Šoštanj and EC (2020e).

Some would argue that if the coal phase-out was postponed, required strategic reserves and CCGTs would be lower, thus making a case for the delay in the closure of coal-fired units in the Šaleška valley. Even though this is true, four factors refute this premise and prove that coal should be phased out by the end of 2027. First, the European Commission is stringent when it comes to authorising state aid and one of its conditions is that the restructuring period should be *"as short as possible"* (European Commission, 2014, p. 11). As I have already explained in subchapter 3.2, the arguments for state aid from 2028 onwards are not supported by the facts. Some experts even question whether state aid could be acquired at all. Second, according to my assessment, the projected annual loss of TEŠ would be roughly EUR 190M as early as 2028 (subchapter 3.2), whereas the total cumulative costs of investing in OCGTs and CCGTs would amount to EUR 346M. Paying the annual loss of TEŠ for only two years (2028 and 2029) would already be more expensive than setting up all the mentioned power plants. Similar is true for cost prices – in 2028, alternative power plants would generate electricity at a lower cost price than TEŠ (see Table 7). Third, besides alleviating the short-term problem of losing TEŠ's electricity generation, strategic reserves and CCGTs would contribute to covering part of future peak load and abrupt fluctuations in output from variable renewable energy power plants. Especially safeguarding against fluctuations would make investments in strategic reserves indispensable regardless of coal-fired unit 6 in Šoštanj. Lastly, natural gas is less carbon-intensive than coal and gas-related technologies are easier to decarbonise than coal technologies.

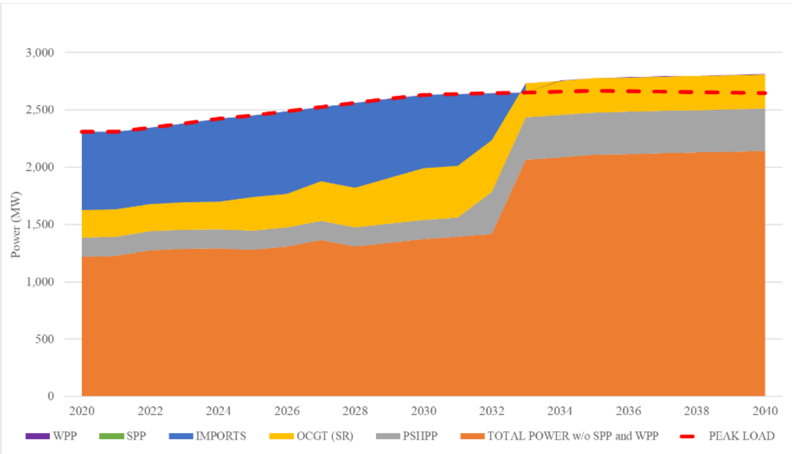
5.6 Covering peak load during wintertime and exposure to imports

An electric power system is not primarily designed to cover the average load on a typical day but to secure a supply that matches peak load. Therefore, it is of the highest importance to outline an energy plan that will guarantee a stable and reliable system capable of meeting peak load, occurring in the evening in winter, mainly in January (ELES, 2020, p. 36). Peak load until 2040 and the role of demand-side management have already been outlined in subchapter 2.4.

To test whether my decarbonisation plan could cover peak load, I have devised two scenarios to assess the range of imports needed to cope with peak load in the future (conversation with a GEN-I employee). Under the first scenario power output from variable power plants (solar, wind, hydro) during peak load would be minimal, while under the second scenario their power output would be maximal. Average peak load power output has been used for the remaining energy sources and power plants in both scenarios. Based on past data, peak load was defined as the period between 8:00 and 11:00 and between 18:00 and 20:00 of January working days. For CCGTs, average peak load capacity factor of TEŠ was used (0.71). Minimum and maximum power outputs were obtained based on the averages of the lowest and highest 10% of hourly peak load capacity factors. The hourly capacity factors for solar and hydropower plants are based on Slovenian statistics from 2019 to 2021 (to control for potential yearly fluctuations), whereas the numbers for wind power plants were taken from data for Austria. Since river flows have been decreasing in the summer due to climate change and not in the winter (Agencija Republike Slovenije za okolje, 2018, pp. 39, 144), the future hourly peak load capacity factor of HPPs was not adjusted. The availability factor of PSHPPs was assumed to be 0.9. The results are presented in Figures 24 and 25.

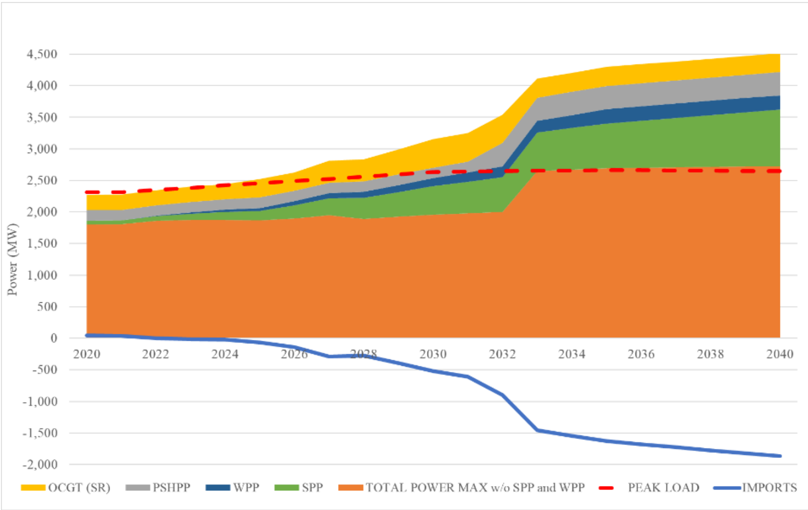
In the minimum domestic power output scenario (Figure 24), in 2040, WPPs, SPPs and HPPs would provide 3 MW, 0 MW and 318 MW, respectively, and imports would not be required to cover peak load from 2033 onwards. As for the maximum domestic power output scenario (Figure 25), in 2040, WPPs, SPPs and HPPs would supply 225 MW, 898 MW and 903 MW, respectively, and Slovenia would begin to export electricity as early as 2023.

Figure 24: Covering peak load – minimum domestic power output scenario (MW)



Source: own work.

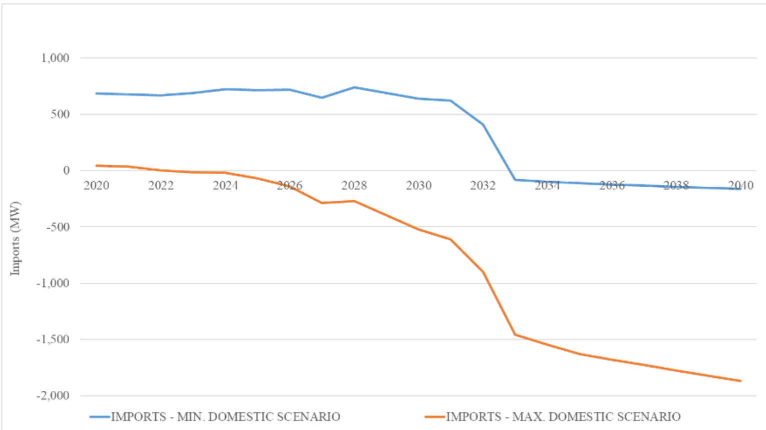
Figure 25: Covering peak load – maximum domestic power output scenario (MW)



Source: own work.

Looking more closely at Figure 26, in the scenario of maximum output, and supposing that strategic reserves would operate at maximum capacity, Slovenia would begin to export electricity as early as 2023 and could sell abroad up to 1,869 MW in 2040; even in 2028, one year after coal phase-out, it could export 272 MW. In the minimum domestic power output scenario, and assuming strategic reserves operating at maximum capacity, imports would rise from 677 MW in 2021 would top at 738 MW in 2028 and then gradually decrease. Since 2033, imports would not be required. To put such values into perspective, import net transfer capacities for winter 2019 equalled 3,110 MW (ELES, 2020, p. 104), indicative values for 2030 are expected to amount to 5,080 MW (ELES, 2020, p. 104) and maximum imports during peak load in January 2019–2021 stood at 1,208 MW (at 9:00 on 23 January 2019) (ELES database). Hence, even in the worst-case scenario, imports could be met without significant difficulties.

Figure 26: Imports during peak load times – minimum and maximum domestic power output scenarios (MW)



Source: own work.

5.7 Automatic frequency restoration reserve (aFRR)

The proposed decarbonisation plan would have considerable effects on ancillary services. Currently, ±60 MW of automatic frequency restoration reserve (aFRR) is leased by ELES and covered by two qualified players (ELES, 2020, pp. 99–100), supplying +92 MW and –91 MW at maximum. With only two providers and a limited quantity of available reserve, it is challenging to provide aFRR throughout the year and impossible to establish a liquid and competitive aFRR market. For example, the HSE Group, which owns two thirds of the existing aFRR capacities, in some cases cannot realise even 10 MW (conversation with an expert at ELES). However, some positive changes have occurred since 2020. A new aFRR provider, owning batteries with almost ±30 MW, has improved the quality of the service, enabled shorter activation times and relieved other suppliers of their burden. Nevertheless, in the following years, the aFRR required will increase due to new intermittent power stations. ELES predicts the aFRR will be ±72 MW in 2030 (ELES, 2020, p. 99); however, recalculation of their value is required as my plan envisions more solar power stations and wind power stations.[24] Additionally, ELES calculated that 4–6 MW of aFRR are required for every 100 MW of new intermittent renewable energy power stations from when their installed capacity exceeds 500 MW onwards (correspondence with Mervar). The difference between my and the ELES scenario is 1380 MW, thus ±141 MW of aFRR will be required by 2030 instead of ±72 MW. Based on my projected deployment of variable renewable energy power plants from 2030 onwards, the aFRR required would equal 235 MW and 298 MW in 2035 and 2040, respectively. Since unit 6 of TEŠ provides ±45 MW of aFRR, it is important to take into account its closure date.

In the following part, I will estimate the future size of available aFRR, which hinges on the foreseen development described throughout the master’s thesis. I expect that aFRR capacities of the existing power plants, batteries and other devices (without TEŠ from 2028 onwards) will remain intact. Since demand-side management is more appropriate for mFRR than aFRR provision, I assume that 7.5% of its total capacities will be aFRR-eligible (conversation with an ELES employee). As not all batteries will be appropriate or available and not all their owners will be keen to participate in the scheme, I presume that 90% of in-front-of-the-meter batteries and 30% of behind-the-meter battery storage systems will participate in the aFRR market (conversation with an ELES employee). Additionally, values for JEK2 and PČHE Rudar will equal 10% and 20%, respectively (see subchapters on JEK2 and PČHE Rudar). The EU platforms for leasing and exchanging FRR power (not only energy) that will be available in the upcoming years could provide up to 100 MW by 2035 (conversation with an ELES employee) and 140 MW by 2040. The aFRR could account for a quarter of these capacities. The last of the aFRR-eligible technologies are electrolysers, whose excellent characteristics for aFRR provision have already been described in

24 SPPs: 3000 MW vs. roughly 1650 MW (ELES, 2020, pp. 84–85; Vlada Republike Slovenije, 2020, p. 43). WPPs: 180 MW vs. roughly 150 MW (ELES, 2021, pp. 84–85; Sistemski operater distribucijskega omrežja, 2021, p. 127; Vlada Republike Slovenije, 2020, p. 43).

subchapter 5.4. Their promising aspects are additionally amplified by their high utilisation rates. Since the 220 MW electrolyser attached to JEK2 is to have a capacity factor of 0.9 (subchapter 5.4), 20% of its installed capacity (i.e. 44 MW) dedicated to providing aFRR is envisioned. The remaining electrolysers with an utilisation rate of 0.3 until 2033 and 0.45 from 2033 onwards (subchapter 5.4) are expected to supply aFRR with 7.5% of their installed capacity. The results are shown in Table 53 and Figure 27.

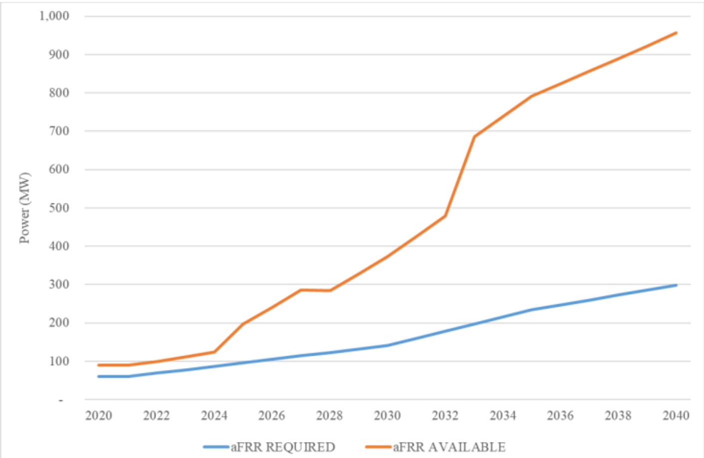
My decarbonisation plan would provide more than enough available aFRR to ensure the reliability of supply. Even coal phase-out would not present a real threat to the system. Moreover, the scenario would bring much-needed liquidity and competition to the market, reinforce the system and lower the lease costs.

Table 53: Automatic frequency restoration reserve (aFRR) 2021–2040 (MW)

AUTOMATIC FREQUENCY RESTORATION RESERVE (aFRR)	2021	2025	2028	2030	2035	2040
aFRR REQUIRED	60	96	123	141	235	298
CURRENT CAPACITIES	90	90	45	45	45	45
DEMAND-SIDE MANAGEMENT	0	2	14	23	56	113
aFRR LEASED ON EU MARKET	0	2	9	14	25	35
NEW POWER PLANTS	0	0	0	0	111	111
ELECTROLYSER AT JEK2	0	0	0	0	44	44
OTHER ELECTROLYSERS	0	1	6	9	49	116
IN-FRONT-OF-THE-METER BATTERIES	0	77	158	212	347	369
BEHIND-THE-METER BATTERIES	0	26	53	71	116	123
TOTAL aFRR AVAILABLE	90	197	284	373	792	956
DIFFERENCE	30	101	161	232	557	658

Source: own work based on ELES (2020); correspondence with Mervar and conversation with an ELES employee.

Figure 27: aFRR available and required over the 2022–2040 period (MW)



Source: own work.

5.8 Manual frequency restoration reserve (mFRR)

JEK2 would become the biggest power plant in the country and the broader region with an effective capacity of 660 MW[25], if we take the Slovenian share alone, or 880 MW, if we add the Croatian as well. Even though the size of manual frequency restoration reserve required would consequently increase, the country is not obliged to cover the entire mFRR by itself. First, the Guideline on electricity transmission system operation and other energy legislation allow countries to share reserves the size of up to 30% of the reference incident, exchange reserves and take into account aFRR when determining mFRR (internal ELES document). Regarding the latter aspect, in the future, aFRR and mFRR will be combined under the common term of FRR. Second, mechanisms for the exchange of balancing power, similar to MARI and PICASSO, European platforms for the exchange of balancing energy, are under development. Lastly, since 2014, along with Croatia and Bosnia and Herzegovina, Slovenia has been part of the SCB block, enabling transmission operators to share reserves among themselves and jointly cover the biggest power plant (biggest incident) in the block (ELES, 2020, pp. 97–98). The benefits of this union are tangible and clear – instead of +348 MW of mFRR (i.e. half of installed capacity of NEK1), ELES needs to secure only +250 MW (ELES, 2020, p. 100).

The easiest way to tackle the increase in mFRR required would be to lease an entire additional mFRR on the then established platforms similar to MARI and PICASSO. However, it would be overly optimistic to bet everything on renting balancing power from other European countries. First, the system operator is obliged to simultaneously purchase balancing power and cross-zonal transmission capacities, causing an increase in the cost of balancing power. Second, transmission operators can only lease FRR-related CZCs under certain conditions. In particular, the FRR-associated lease of CZCs needs to enhance welfare to a greater extent than if the same capacities are used by other actors in different segments of the energy market (internal ELES document). Lastly, leasing balancing power is further limited as only a maximum of 10% of CZCs can be utilised for FRR purposes (conversation with an ELES employee). The situation could be partly alleviated by the new electric lines that would primarily run to Austria, which, alongside Germany, represents Slovenia's most promising FRR pool. However, such projects have not yet been considered or are likely to face many difficulties and delays. Neither Western Balkans, with all the regional instabilities and turbulent energy transition lying ahead, nor import-dependent Hungary, which will use newly constructed electric line Cirkovce–Pince primarily for its own needs, can be a safe bet. Thus, it seems sensible to predict that in 2033, when the second nuclear power plant is to be finished, it would be possible to lease roughly 100 MW of FRR on the European balancing power market. Of these, three quarters could be dedicated to fulfilling mFRR

25 220 MW out of 1100 MW would be connected to the electrolyser. In the case of an outage, there would be no obligation that this share of missing electricity from JEK2 should be immediately replaced by grid electricity. Thus, this part of the second nuclear power plant does not need to be included when estimating ancillary services (conversation with an ELES employee).

obligations. Therefore, it is more reasonable to primarily turn towards the highly beneficial SCB block and keep the agreement alive. For the short to medium term, renting balancing power on the EU market appears a valuable complement to the SCB block but not its substitute.

If I take into the account positive aFRR when sizing positive mFRR, assume the future existence of the SCB block, apply the proportionality principle enshrined in the SCB agreement (internal ELES document), envision the biggest positive incident being greater than the probabilistic positive requirement (internal ELES document) and second nuclear reactor becoming the largest power plant in the block (ELES, 2020, p. 101), then the mFRR required in the year 2033 would amount to 256 MW (Table 54).

Table 54: Increase in manual frequency restoration reserve (mFRR) due to JEK2 (MW)

Regulation zone	Biggest positive incident	Positive mFRR required	Share of positive mFRR required	Positive mFRR	Positive aFRR (2033)	Final positive mFRR (2033)
SLO	660	660	0.52	453	197	256
HRV	348	348	0.27	239		
B&H	273	273	0.21	188		
SCB block	880	880		880		

Source: own work based on internal ELES document.

As the table shows, in 2033, when the construction of JEK2 would be finished, the positive mFRR required would amount to 256 MW, comparable to 250 MW for 2021. Since roughly 75 MW of mFRR could be leased on European balancing power platforms in the early 2030s and a domestic increase in mFRR providers (e.g. PČHE Rudar, electrolysers, demand-side management through aggregators), the predicted mFRR size could be easily covered with domestic and foreign actors. Even more so as announced shutdowns of some OCGTs, described in subchapter 5.5, have already been included in the calculations on strategic reserve, thus not reducing existing mFRR capacities. Additionally, extra bidders would deepen the competition, lowering the offered mFRR prices and subsequently reducing total mFRR costs.

5.9 Transmission and distribution network

Modern, robust and smart transmission and distribution networks should be the integral parts and facilitators of a green transition, but such a stage can only be achieved with a profound transformation. Financial, human, technical and other resources will be needed, and genuine communication with local communities, nature conservationists and municipalities ought to be pursued from the very start of the project. Additionally, higher network charges, more favourable borrowing conditions, a better working environment, new employments and other challenges will have to be addressed. However, it is beyond the scope of my master's thesis to dig into these issues and develop a detailed plan on how to solve these issues. Instead, what this subchapter aims at is to estimate the means required to make the transmission and distribution networks robust enough to enable and accelerate the green transition. The transmission network and the distribution network will be assessed separately.

5.9.1 Investments required in transmission network

In their Slovenian Network Development Plan from 2021 to 2030, ELES estimates that almost EUR 530M should be invested in the transmission network in order to adapt to the future challenges throughout the 2021–2030 period (2020, p. 192). More precisely, EUR 204M should be allocated for constructing new and reconstructing the existing 400kV, 220 kV and 110 kV electric lines, EUR 114M for setting up new and reconstructing the existing distribution transformer substations and transformer substations, EUR 22M for secondary equipment, EUR 25M for telecommunications and upgrades to the information services, EUR 60M for large investments in the operation of the system and EUR 105M for other investments by 2030 (ELES, 2020, pp. 185–192). Since some conditions and assumptions made by ELES, e.g. on the development of renewable energy power plants, differ from ours, I have made some adjustments. As I have assumed similar capacities of wind turbines as ELES, reduced the capacity of wind parks in advance due to envisioned grid-related difficulties, proposed multiple investments at already established energy location (see subchapter 4.1 on solar energy) and envisioned 1,431 MW of SPPs linked to the transmission network, whereas ELES has predicted a negligible increase on its grid, it seems sensible to predict a 50% increase of ELES proposed investments in power line by 2030. My plan thus suggests EUR 306M of electric line-related expenditures, whereas ELES assumes EUR 204M. I have also increased ELES's proposal regarding distribution transformer stations by 15% (EUR 131M) for two reasons. First, the majority of 1,431 MW of solar parks connected to the transmission network would be located within the 23 distribution transformer substations that could, without additional upgrades, secure roughly 1,495 MW of additional power plants (ELES, 2021a). Second, ELES is already projecting to substantially upgrade substations. As for the investments in secondary equipment, telecommunications, information services, the system's operation and other investments that amount to EUR 212M in total, I have raised the total amount for 5%, i.e. an additional EUR 11M. To sum up, my plan requires EUR 660M of investments in the transmission network by 2030, EUR 130M more than the amount proposed by ELES.

For the 2031–2040 period, I can only give highly speculative estimates because, to the best of my knowledge, no Slovenian studies have been conducted on this subject (for EU, see European Network of Transmission System Operators for Electricity, 2020). This can be presumably attributed to the vast uncertainties around the detailed path of the grand transformation. Still, wind parks deployment only up until 2035, siting bigger constructions at already well-connected energy sites (see 4.6, 5.4 and 5.5), and usage of demand-side management, batteries, underground pumped storage hydropower stations and electrolysers can all decrease the amount of the expenditures required. Additionally, most of the investments in the 2022–2030 period would provide benefits and services throughout the subsequent decade. On the other hand, a continuity of funds will be required if the deployment of solar power plants and upgrades to the existing energy locations are to continue. Europe's interconnection needs and the reality of abundant electricity from variable RES flowing across the continent will spur further investments. To deal with such conditions, pan-European electricity highways connecting various parts of the European continent have been proposed, all but calling for additional expenditures in cross-border as well as interior transmission capacities (ELES, 2020, pp. 145–146; European Network of Transmission System Operators for Electricity, 2020). To sum up, I assume that the same amount of investments will be necessary for both the 2022–2030 and the 2031–2040 periods. In total, investments in the transmission network for the 2022–2040 period would thus amount to EUR 1,319M.

5.9.2 Investments required in distribution network

The distribution network will have to undergo even more significant changes than the transmission network. SODO, the Slovenian electricity distribution system operator, predicts that EUR 4,212M will have to be spent on upgrading the grid for future challenges between 2021 and 2030 (Sistemski operater distribucijskega omrežja, 2020, p. 136). In terms of investment objectives, 18% are to be dedicated to addressing and resolving the inadequate quality of supply, 14% to repairing the decrepit parts of the network, 23% to dealing with the rapid deployment of power plants using variable RES and 44% to coping with rising loads (Sistemski operater distribucijskega omrežja, 2020, p. 140). As the last two elements are most directly linked to the decarbonisation, I shall focus on them. They represent 67% of total investments. My plan predicts fewer solar and wind power plants connected to the distribution network by 2030 compared to what SODO suggested (Sistemski operater distribucijskega omrežja, 2020, p. 36). I propose to locate the majority of solar capacities on degraded areas, parking lots, industrial sites and commercial buildings, and only a smaller part rest with single houses and block of flats, whose load profile overlaps the least with the solar generation diagram. The burden on the distribution network will also be noticeably eased with 850 MW of batteries installed at homes, industries, commercial buildings and other places that are to come into operation by 2040 (subchapter 5.3). Lastly, advanced metering systems and demand-side management can significantly relieve the network and thus lower the costs required (subchapter 5.2). Based on the factors above, it is reasonable to assume that the funds for dealing with load increases and faster deployment of power plants using variable RES would be 50% lower than predicted by SODO, i.e. from EUR 2,822M to EUR 1,411M. SODO's data is used and left intact for other parts of the investment portfolio (i.e. addressing and resolving the inadequate quality of supply and repairing the decrepit parts of the network). Aggregate investments in the distribution network would thus amount to EUR 2,801M in the 2022–2030 period.

As we have already seen with the transmission network, it is extremely hard to predict the investments needed for the 2031–2040 decade (conversation with a SODO employee). That being said, the expenses are expected to drop below the levels envisioned for the present decade due to the expansion of DSM, battery storage and electrolysers and the WPPs deployment occurring at a slower pace, only up to 2035 and mainly on the transmission network. Additionally, at least part of the investments made in the current decade will provide benefits throughout the following decade. On the other hand, solar power stations are envisioned to be rolled out at a similar pace as throughout this decade. Therefore, I assume that the total costs for the 2031–2040 period will be 30% lower than the expenses for this decade, i.e. EUR 1,961M instead of EUR 2,801M. In total, the investments into the distribution network would amount to EUR 4,762M between 2022 and 2040.

By adding up the investments in the transmission and distribution networks, EUR 3,461M and EUR 2,620M will be required for the 2022–30 and the 2031–40 periods, respectively. In total, EUR 6,081M ought to be spent between 2022 and 2040 (Table 55).

Table 55: Investments required in transmission and distribution networks from 2022 to 2040 (EUR M)

NETWORK INVESTMENTS	2021–30 (ELES/SODO)	2022–30	2031–40	2021–40
TRANSMISSION NET.	530	660	660	1,319
DISTRIBUTION NET.	4,212	2,801	1,961	4,762
TOTAL (EUR M)	4,742	3,461	2,620	6,081

Source: own work based on Sistemski operater distribucijskega omrežja (2020) and ELES (2020).

6 ELECTRICITY BALANCE, PACE OF DECARBONISATION AND ECONOMIC VIABILITY

6.1 Electricity balance

6.1.1 Electricity balance and import dependence

Table 56 and Figure 28 show the electricity balance for the 2020–2040 period under my scenario, whereas Figure 29 plots import dependence throughout the observed era. Tables 2 and 3 in the Appendix show the detailed generation disaggregated by energy source and by power plant type. These results lead to the conclusions presented below.

Domestic electricity generation would double in the next 20 years, from roughly 12.9 to 25.7 TWh. Considering direct consumption (including losses) alone, Slovenia would have an export surplus by 2033. However, since a significant amount of electricity consumption will be needed for hydrogen production, greatly increasing final consumption, Slovenia would depend on imports throughout the observed period except few years after 2033. The import share would gradually increase from roughly 10% in 2020 to 17% in 2028 and then fall to -2% after the construction of JEK2. As hydrogen production would start to take off in about the same period, imports would follow suit, reaching 9% in 2040. As has already been explained (subchapter 4.8), a reasonable amount of imports generally enhances welfare and is most of the time economically beneficiary. However, imports can also threaten the entire system's stability if they are excessive and not coupled with adequate strategic reserves. Hence, the right balance needs to be struck. The threshold of 25% of yearly consumption set by NECP for imports (Žerdin et al., 2021, p. 195) would not be exceeded during the observed era, not even immediately after coal phase-out. The highest import dependence would occur in 2028 when it would reach 17%. To put these values into perspective, from 2010 to 2020, electricity import dependence varied between 1.8–18.2% (Gospodarska zbornica Slovenije, 2021). An additional 212 MW of strategic reserves by 2028, i.e. 452 MW in total, and 285 MW of CCGTs would render the system more robust and secure. As demonstrated in subchapters 5.5 and 5.6, the proposed plan would also make it possible to cover peak load and effectively cope with fluctuations in generation due to intermittent output of renewable energy power plants.

Since NEK1 will be most likely shut down by the end of 2043, we should consider what will happen to import dependence in the year after its closure. As my focus is on the period until 2040, when the electric power system should be fully decarbonised, the outlined developments for 2041–2044 are highly speculative. If solar power plants, batteries and electrolysers are gradually deployed and two small modular reactors (SMR) with a capacity of 250 MW each are constructed by 2044, we get the results plotted in Figure 29. As SMRs should become commercially available in the first part of the 2030s (Nuclear Energy Agency, 2021, p. 47), the first SMR would be constructed in 2041 and the second in 2044. Import share would vary between 2–7% during the 2041–2044 period.

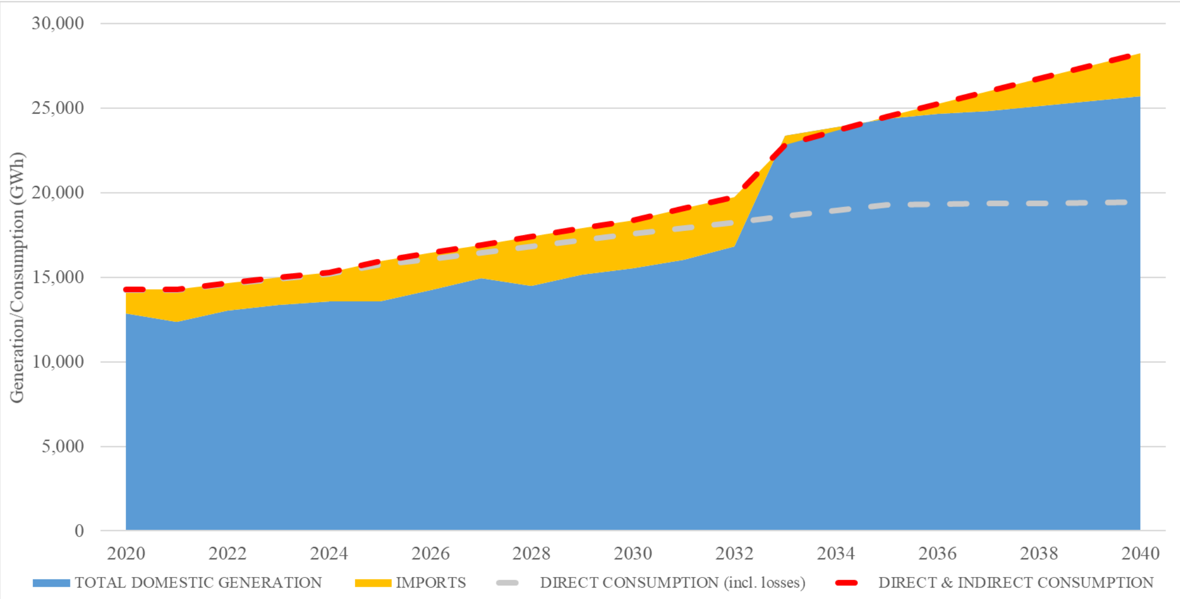
To conclude, under the proposed scenario, domestic electricity generation would double in the next 20 years, but Slovenia would nevertheless remain import-dependent for the most part of the observed era, largely due to high hydrogen production. Still, predicted import dependency would be generally economically rational and manageable, firmly stay within the limits prescribed by the NECP and not threaten security of supply even shortly after coal phase-out.

Table 56: Electricity balance 2021–2040 (GWh)

ELECTRICITY BALANCE (GWh)	2021	2025	2030	2035	2040
GENERATION ON TN	10,880	11,665	11,900	19,482	20,008
GENERATION ON DN	1,472	1,923	3,626	4,880	5,717
TOTAL GENERATION	12,351	13,588	15,526	24,362	25,726
IMPORTS	1,931	2,360	2,857	133	2,507
IMPORT DEPENDENCY (%)	14	15	16	1	9
DIRECT CONSUMPTION (incl. losses)	14,253	15,723	17,557	19,303	19,442
CON. BY BATTERY STORAGE	30	199	497	796	845
CON. BY ELECTROLYSERS	0	26	329	4,396	7,945
FINAL CONSUMPTION	14,282	15,949	18,383	24,494	28,233

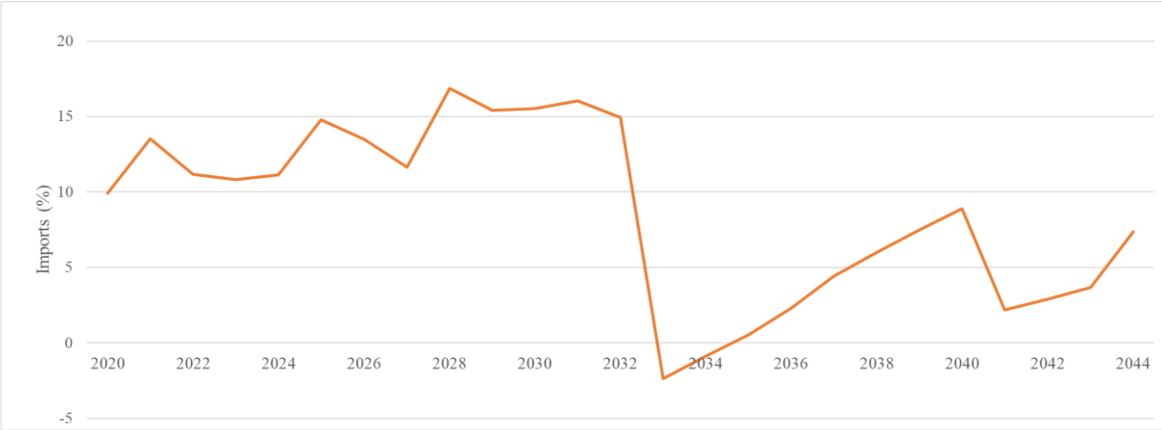
Source: own work.

Figure 28: Electricity balance 2021–2040 (GWh)



Source: own work.

Figure 29: Import dependence 2021–2044 (%)

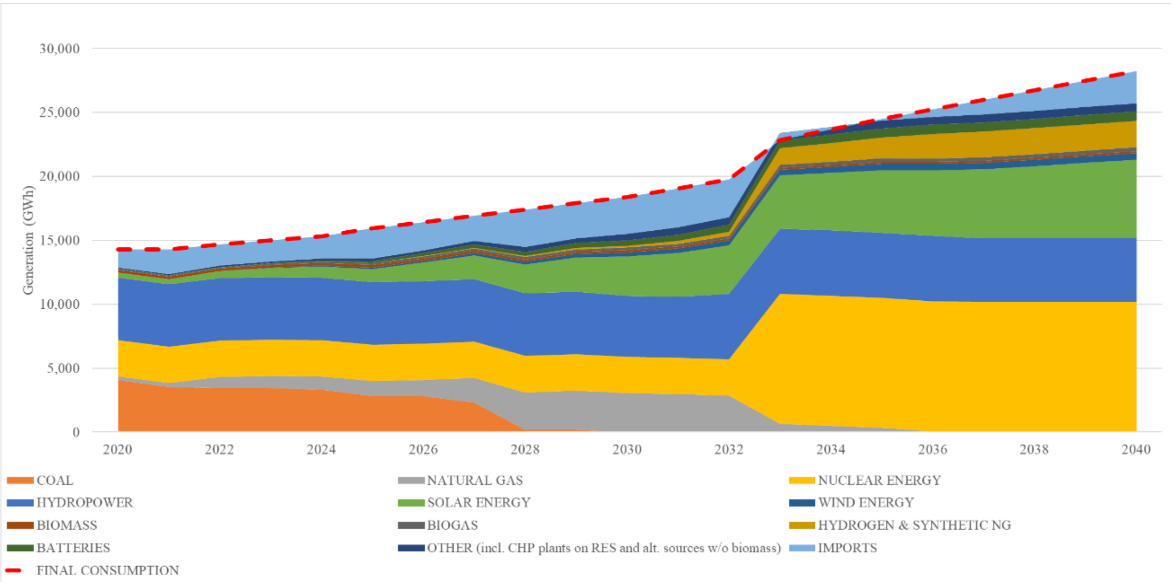


Source: own work.

6.1.2 Structure of electricity generation by energy sources

Table 57 and Figure 30 present more detailed information on the role of various energy sources in future electricity generation. According to my plan, in 2040, the Slovenian electric power system would mainly depend on nuclear energy, solar energy, hydropower, hydrogen (with its derivatives) and imports. In the shorter term, coal would be replaced predominantly with solar energy, imports and natural gas. The latter would play a short but essential role as a bridge fuel.

Figure 30: Electricity generation by energy source 2020–2040 (GWh)



Source: own work.

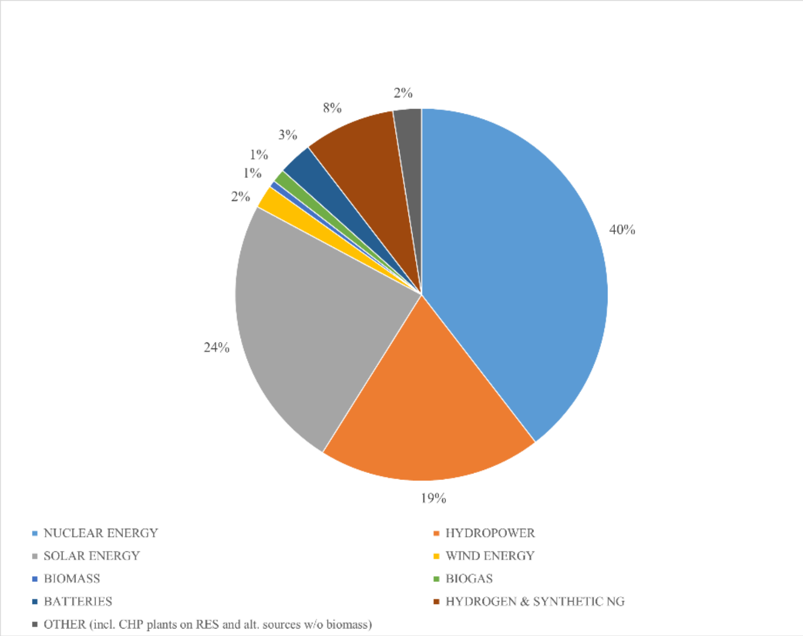
Table 57: Electricity generation by energy source 2021–2040 (GWh)

GENERATION BY ENERGY SOURCES (GWh)	2021	2025	2030	2035	2040
COAL	3,535	2,821	0		
NATURAL GAS	300	1,178	3,041	345	
NUCLEAR ENERGY	2,844	2,844	2,844	10,172	10,172
HYDROPOWER	4,892	4,892	4,784	5,091	4,984
SOLAR ENERGY	380	1,026	3,077	4,871	6,153
WIND ENERGY	5	152	300	521	521
BIOMASS	187	187	187	153	153
BIOGAS	97	147	210	254	299
BATTERIES	27	179	448	716	761
HYDROGEN & SYNTHETIC NG		8	111	1,639	2,044
OTHER (incl. CHPP on RES and alt. sources w/o biomass)	84	191	524	599	639
TOTAL GENERATION	12,351	13,588	15,526	24,362	25,726
IMPORTS	1,931	2,360	2,857	133	2,507
TOTAL CONSUMPTION	14,282	15,949	18,383	24,494	28,233

Source: own work.

According to my calculations, in 2040, nuclear energy would provide 40% of domestic generation, solar energy 24%, hydropower 19%, and hydrogen with its derivatives 8% (Figure 31). Other energy sources would represent the remaining 9%.

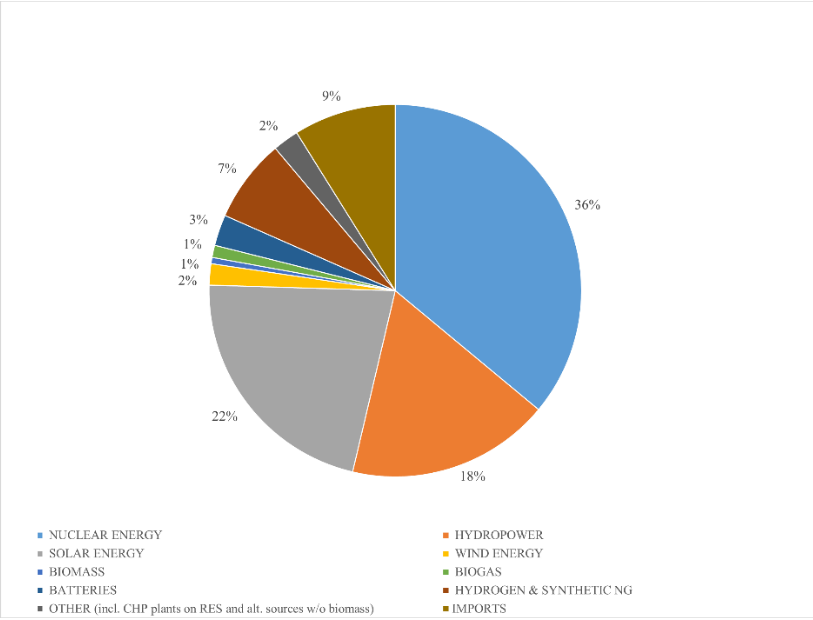
Figure 31: Share of various energy sources in domestic generation in 2040 (%)



Source: own work.

Assessing the share of various energy sources in final electricity consumption in 2040 (Figure 32), nuclear energy would cover 36% of electricity needs, solar energy 22%, hydropower 18%, imports would contribute 9% and hydrogen with its derivatives 7%. Other energy sources combined would meet 9% of electricity requirements in 2040.

Figure 32: Share of various energy sources in final electricity consumption in 2040 (%)



Source: own work.

To sum up, electricity production in Slovenia as presented above would be diversified and would not rely excessively on a sole power plant or energy source. Such a structure would make the system more robust and better prepared for future challenges.

6.2 Pace of decarbonisation

As I have already argued in the initial part of the master's thesis, to stay in line with the Paris agreement, Slovenia should reach net-zero emissions in its electric power system by around 2035. The carbon intensity of the proposed programme was calculated based on the life-cycle GHG emissions of different energy sources, taking into account raw materials, transportation, construction and similar activities, and presented in Table 2. Such an approach is more comprehensive, accurate and just, but it's not used very often because it can inflate values and make promises (mostly given by developed countries and private entities) seem less grandiose. The methodology used in the NECP appears to only calculate downstream emissions in a narrower sense (Portal Energetika, 2019). As my broader approach takes into emissions over the whole life-cycle of a power plant, some future emissions are already locked in (most notably from existing HPPs, see Figure 33), and the proposed plan will by necessity entail some GHG emissions even in 2040. These could be taken from the atmosphere and sequestered by natural sinks (e.g. Slovenian forests), by which the electric power system would reach net-zero emissions.

Since the carbon intensity of hydrogen and imports are highly country- and time-specific, they should be devised individually. Hydrogen's carbon content depends on the energy source used for its production and is thus calculated based on the average carbon intensity of domestic electricity. A similar technique is taken for imports because all EU countries will phase out fossil fuels and gradually decarbonise their electricity generation (see Pietzcker, Osorio & Rodrigues, 2021). Such procedures, also dubbed consumption-based approach, have been mainly excluded from national accounts, which have been using the production-based methodology. My path, however, is more thorough, just and accurate, and it prevents a situation where a country relying on imports would be perceived as more climate friendly than a country independent of imports solely due to the difference in generation locations. Life-cycle GHG emissions of time-dependent hydrogen with its derivatives and time-dependent imports are shown in Table 58.

Table 58: Life-cycle GHG emissions by time-dependent energy source (tCO2-eq./GWh)

LIFE-CYCLE GHG EMISSIONS BY TIME-DEPENDENT ENERGY SOURCES (t CO2-eq./GWh)	2020	2025	2030	2035	2040
HYDROGEN & SNG	286	228	110	17	10
IMPORTS	286	228	111	19	11

Source: own work.

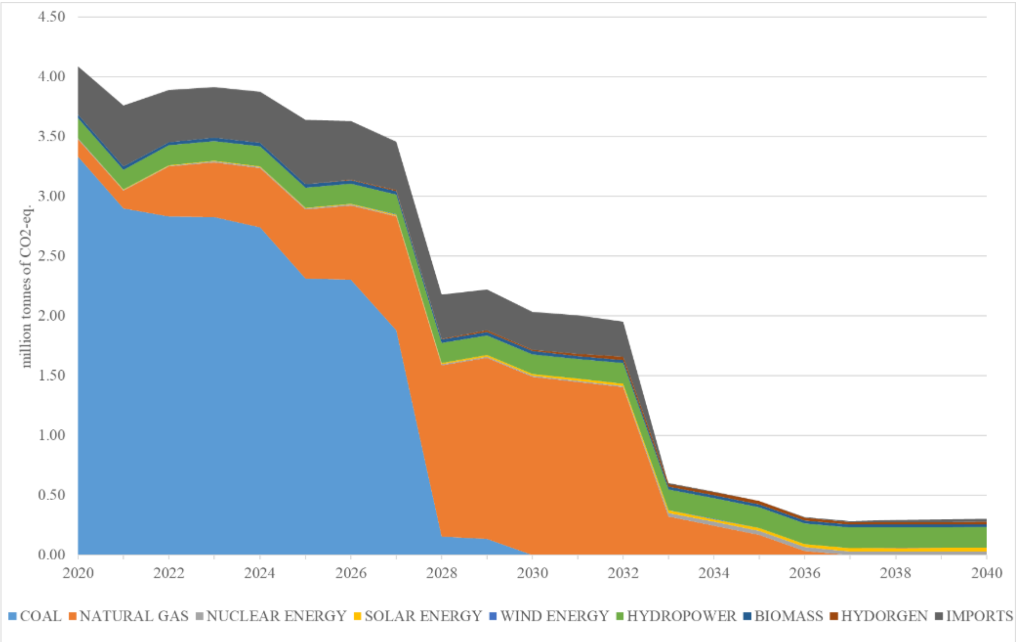
Table 59 and Figure 33 show the decarbonisation pace according to the proposed plan. The carbon footprint of the Slovenian electric power system would be halved by 2030 with an additional 39% reduction by 2035. Around 2036, the electric power sector would become fossil fuel-free without generating direct GHG emissions. All emissions at that time would already be locked in due to previous upstream operations (e.g. construction of power plants). As these emissions would be infinitesimal and unavoidable, they could be offset through carbon sinks. Moreover, using a mainstream methodology, thus taking into account only downstream emissions and excluding imports, Slovenia would achieve full decarbonisation of the electric power system without negative emissions by around 2036. Under the proposed scenario, Slovenia would therefore achieve the long-term climate target sketched in the initial part of the master's thesis but would fail to reach the short-term goal (i.e. 2030). Nevertheless, it would meet the UN demand for cutting the emissions in half by the end of this decade, target based on the conditions under the Paris agreement (United Nations, 2019). My proposition would also exceed national and EU climate targets. The NECP predicts that in comparison to 2020, GHG emissions would decrease by 30% and 74–85% in 2030 and 2040 (Portal Energetika, 2019). Assuming the EU ETS-wide reduction target, determined in the anticipated reform, will amount to 63% in 2030 compared to 2005 (Pietzcker, Osorio & Rodrigues, 2021, p. 4), the proposed plan would surpass the objective with a projected 73% decrease.

Table 59: The pace of decarbonisation from 2020 to 2040

THE PACE OF DECARBONISATION	2020	2025	2030	2035	2040
TOTAL GHG EMISSIONS with H2 and IMPORTS (mil. tonnes of CO_2-eq.)	4.09	3.64	2.03	0.45	0.30
SHARE OF GHG EMISSIONS RELATIVE TO 2020 (%)	100	89	50	11	7
REDUCTION COMPARED TO 2020 (%)	0	11	50	89	93

Source: own work.

Figure 33: The pace of decarbonisation from 2020 to 2040 (mil. tonnes of CO_2-eq.)



Source: own work.

6.3 Economic viability of the plan

6.3.1 Cost prices in 2021, 2030 and 2040

Cost price, which takes into consideration all the power plant's direct and indirect expenses per electricity generated in one year (Mervar, 2014, p. 101), was calculated based on the methodology developed by German think tank Agora Energiewende (Fürstenwerth, 2014).[26]

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26 Levelised-cost-of-electricity (LCOE), where all the costs and revenues are deducted to determine the average net present cost of electricity production for a generating plant over its lifetime, presents a different metric (International Energy Agency & Nuclear Energy Agency, 2020, pp. 33–40). It is commonly used for making an investment decision. Its reliance on (high) discount rates causes undesirable consequences: it favours short-term, less capital intensive and frequently environmentally destructive investments without taking into account broader considerations (correspondence with Damijan). For example, by taking a 10% discount rate, as proposed by the IPCC, the value of electricity generation decreases by 85% after 20 years. Private, profit-seeking investors generally apply high discount rates (7–12%). From such perspective, everything generated 30 and 40 years from now will bear practically no value. The consequences for capital intensive power plants with a long lifetime, particularly nuclear power plants with an operation period of over 80 years, are clear. LCOE, especially with high discount rates, thus favours investments in environmentally destructive, fossil fuel-based technologies, for example OCGTs or CCGTs, with lower investment costs, shorter construction period and shorter payback period on the one hand, and investments in renewable energy power plants with their own cost-intensive challenges not included in LCOE on the other (see the subchapter 5.1 on tackling excess solar power). These shortcomings are mirrored in the IEA's LCOE calculations (2020, p. 419).

Even if such an approach is relatively reasonable from the narrow perspective of private actors deciding whether to pursue an investment, the electric power system (as holds true for all infrastructure) is essential for the society as a whole with profound effect on all sectors of the society and on the planet's (un)habitable prospects for future generations. Such reasoning constitutes the rationale for state ownership over most power stations and electrical networks. The starkest excesses of high discount rates can be alleviated by choosing more moderate values resembling safe, public or state-supported investments carrying a lower risk or investments generating significant social and environmental benefits (1–3%

With the aim of higher precision, power plant auxiliary supply (i.e. the energy required for a power plant to function under normal conditions; hereinafter referred to as autoconsumption) and decommissioning costs were added to the equation, and finally, equations (6-9) obtained.

Power plant's cost price in year t has been obtained by:

$$P_{t,tech} = \frac{\left(\frac{Capital_{t,tech} + O\&M_{t,tech} + Carbon_{t,tech}}{MWh_{t,tech}} + Decommisioning_{t,tech}\right)}{(1 - Autoconsumption_{tech})} \tag{6}$$

$P_{t,tech}$ = a power plant's cost price in year t (EUR/MWh)

$Capital_{t,tech}$ = a power plant's capital costs in year t (EUR)

$O\&M_{t,tech}$ = a power plant's operation, fuel and maintenance costs in year t (EUR)

$Carbon_{t,tech}$= a power plant's CO_2-related costs in year t (EUR)

$Decommisioning_{t,tech}$ = a power plant's costs of decommissioning in year t (EUR/MWh)

$MWh_{t,tech}$ = the amount of electricity produced by a power plant in year t (MWh)

$Autoconsumption_{tech}$ = the energy required for a power plant to function under normal conditions (%)

$Capital_{t,tech}$ has been defined as:

$$Capital_{t,tech} = Investment\ cost_{t,tech} * \frac{WACC_{t,tech} * \left(1 + WACC_{t,tech}\right)^n}{\left[\left(1 + WACC_{t,tech}\right)^n - 1\right]} \tag{7}$$

$Investment\ cost_{t,tech}$ = a power plant's specific investment cost in year t (EUR/MW)

$WACC_{t,tech}$ = a power plant's weighted average cost of capital in year t (%)

n = lifetime of a power plant (years)

(Drupp, Freeman, Groom & Nesje, 2015)). In ethical terms, that means giving more weight to future generations, the fate of the planet and living beings as such. Still, with a 2% discount rate, electricity generated in 35 years bears approximately half of its value and less than a third in 60 years. Therefore, even though the discounting problem can be partially resolved, inherent biases towards short-term and frequently environmentally destructive power plants persist.
Notably, similarly contrasting and undesired conclusions can be drawn from different discount rates when tackling climate change in broader terms. Lord Nicolas Stern, professor at The London School of Economics and dubbed the father of economics of climate change, has used a 1.4% discount rate and has recommended immediate and robust climate action to avert the direst consequences of climate change, whereas William Nordhaus, professor at Yale and Nobel Laureate in economics, has applied a discount rate of 3–5% and argued for slower and more moderate action. Nordhaus has long claimed that it would be "economically rational" and "optimal" to reach approximately 3.5°C above preindustrial levels, unthinkably above the 1.5°C limit proposed by the IPCC (Hickel, 2018).

$O\&M_{t,tech}$ has been expressed as:

$$O\&M_{t,tech} = fixed\ op.costs_{t,tech} + MWh_{t,tech} * variable\ op.costs_{t,tech} + \frac{MWh_{t,tech} * Fuel\ costs_{t,tech}}{Efficiency_{t,tech-p}} \quad (8)$$

Fixed op. costs$_{t,tech}$ *= fixed operating costs of a power plant per year (EUR/MW/year)*

Variable op. costs$_{t,tech}$ *= variable operation costs of a power plant per electricity generated (EUR/MWh*$_{elect}$*)*

Fuel cost$_{t,tech}$ *= fuel cost per fuel used (EUR/MWh*$_{thermal}$*)*

Efficiency$_{t,tech\text{-}p}$ *= ratio of a unit of energy obtained against the number of equivalent units of energy required to produce it by a power plant in year t (%)*

Where $Carbon_{t,tech}$ has been described as:

$$Carbon_{t,tech} = \frac{MWh_{t,tech} * Carbon\ cost_{t,tech} * Emission\ factor_{t,tech}}{Efficiency} \quad (9)$$

Carbon cost = costs of EU Allowance (EUR/tCO_2*)*

Emission factor = CO_2 *emission factor of the fuel used (t*CO_2*/MWh*$_{thermal}$*)*

I believe that this approach is more thorough than the one used by researchers from the renowned Potsdam Institute for Climate Impact Research (Pietzcker, Osorio & Rodrigues, 2021, pp. 3, 4, 10) but not as detailed as the method used by Mervar (2014, priloga 38). However, Mervar calculated past cost prices mainly from the data available in Annual reports, and not expected future cost prices, where approximations and assumptions should be employed. Since my intention is to estimate future cost prices, it seems reasonable to use the methodology above. This decision is also supported by the results, obtained by applying the described methodology, for the past years, which are similar to Mervar's results, especially if only the cost of debt (and not the cost of equity) is used, as Mervar presumably did (Mervar, 2014, p. 101). However, the approach employed is based on the weighted average cost of capital (WACC), composed of cost of debt and cost of equity, which seems more reasonable because proprietors, whether they be state or private actors, expect and demand returns (correspondence with Damijan). Since TEŠ's cost price for 2021 is based on Mervar's calculations (Žerdin et al., 2021, pp. 106–109), average cost prices for 2030 and 2040, when coal phase-out will have already occurred, could be slightly inflated compared to 2021. It can be therefore said that the cost prices for 2030 and 2040 are rather conservative and lean towards the upper bound.

Where possible, Slovenian data were employed. In other cases, data from reliable, well-founded and scientific sources, excluding organisations with a clear interest in a particular energy source, were used. Table 4 in the Appendix shows all the inputs and sources utilised. In the following paragraphs, potentially the most controversial figures will be explained and discussed.

The price of carbon for the year 2021 was taken as an average for the whole year. Carbon price from 2021 onwards until 2030 was calculated as the average value of the results presented in four studies (Pietzcker, Osorio & Rodrigues, 2021, p. 9; Marcu et al., 2021, p. 28). The rate of increase in the 2030–2040 period was taken from Pietzcker, Osorio and Rodrigues (2021, p. 9) because the other three studies focused only on the period until 2030. The cost of natural gas for 2021 was estimated by combining the mean value of Dutch TTF Gas, leading European benchmark price, and the assumption by Pietzcker, Osorio and Rodrigues (2021, p. 3), by which recent unprecedented price spikes were balanced by more ordinary circumstances. For 2030 and 2040, the average values presented by the European Commission (2020e, p. 47) and Pietzcker, Osorio and Rodrigues (2021, p. 3) were taken. The latter study also provided the future prices of nuclear fuel. The price of (imported) electricity for 2021 was constructed by combining average day-ahead prices of 2020 (0.25 weight) and 2021 (0.75 weight) (ENSO-E database), thus controlling and adjusting for the current exceptional situation, but still taking into account the rising costs of emission allowances, which are here to stay. Electricity prices for 2030 were gathered by using EEX German Power Futures (November and December 2021) for the year 2030, where baseload electricity was given a weight of 0.7 and peak-load electricity a weight of 0.3 (Mervar, 2019a, p. 9). Obtained amount was then augmented for 3 EUR/MWh to take into consideration the expected future disparities between German and Slovenian electricity prices and the cost of trans-border transfer capacities (conversation with a GEN-I employee). Since the value obtained is similar to the one from the EU Reference Scenario for 2030 (European Commission, 2016b, p. 6), the data for 2040 was taken from the EU Reference Scenario (European Commission, 2016b, p. 6). The average electricity expenses (EUR/MWh) of ČHE Avče from 2018 to 2020 presented the electricity costs for batteries, ČHE Avče and PČHE Rudar (Soške elektrarne Nova Gorica, 2021, p. 27; Soške elektrarne Nova Gorica, 2020, p. 25; Soške elektrarne Nova Gorica, 2019, p. 25). This value was then decreased by EUR 5 per decade as price volatility and price spreads are assumed to widen. For electrolysers, as their capacity factor is higher than the one of the batteries and PSHPPs, the cost of electricity is assumed to be higher – 48 EUR/MWh throughout the observed period (correspondence with Mervar), which could be a potentially slightly conservative assumption.[27] For the electrolyser attached to JEK2, the cost price of JEK2 was applied for

[27] The figure seems realistic as it is in line with or higher than the cost prices of solar and wind power plants. Such an average also enables electrolysers to use in some cases more expensive electricity and cheaper one in others. Still, 48 EUR/MWh could also be somewhat inflated as the value is higher than the electricity cost in the worst-case scenario envisioned by Bloomberg NEF (Bloomberg NEF, 2020, pp. 2–3). Additionally, in the last few years, ČHE Avče bought electricity at a substantially lower price than 48/MWh (Soške elektrarne Nova Gorica, 2021, p. 27; Soške elektrarne Nova Gorica, 2020, p. 25; Soške elektrarne Nova Gorica, 2019, p. 25). However, as ČHE Avče has a capacity factor of 0.15 and proposed electrolysers 0.45, the comparison holds only partly. Finally, better coordination and joint projects with

its electricity expense. For power plants running on hydrogen, the cost of hydrogen, presented in the subchapter 5.4.3, was increased by 10% to incorporate the transport and storage costs (Bloomberg NEF, 2020, p. 5). For the existing HPPs and NEK1, Mervar's cost prices were employed (2019a, p. 9); whereas for TEŠ, figures presented by ELES and Mervar were used (Žerdin et al., 2021, pp. 104–110) and adjusted for higher carbon costs. The costs of decommissioning JEK2 were assumed to amount to 5 EUR/MWh, as such expenses for Hinkley Point C were estimated at 3 EUR/MWh (ENCO, 2020, p. 32) and the costs for NEK1 have amounted to below 5 EUR/MWh for almost the entire operation period (Sklad za financiranje razgradnje NEK, n. d.).[28] I predicted that 1 EUR/MWh would be required for the decommissioning of other power plants. Most of the other assumptions were taken from Pietzcker, Osorio and Rodrigues (2021). All variables are real, i.e. net of inflation. Lastly, since low-carbon energy sources, especially nuclear energy, are capital-intensive, the weighted average cost of capital presents a major determinant. However, most energy models apply a uniform WACC across technologies, countries and time periods (Bachner, Mayer & Steininger, 2019, p. 19). For example, IEA and the OECD Nuclear Energy Agency (2020) compare the LCOE of various technologies by employing a uniform WACC of 3, 7 or 10% across the board. Such assumptions are false and misleading, as WACC varies notably between different technologies, countries and over time (Egli, Steffen & Schmidt, 2019; Polzin et al., 2021; Bachner, Mayer & Steining, 2019).

The WACC of a particular technology is determined, among other factors, by the latter's capital intensity, maturity, developmental stage, (non)existence of economies of scale, market share, (un)limited access to the capital market and share of debt and equity financing, as well as the country's climate and broader policy framework, its stability and its macroprudential measures (Egli, Steffen & Schmidt, 2019; Polzin et al., 2021; Bachner, Mayer & Steining, 2019). These aspects have a significant effect on how investors perceive and evaluate risk, reducing (or increasing) the risk premium and, consequently, the WACC. The inaccurate assumptions mentioned above have detrimental effects: if a uniform WACC is applied across technologies, countries and time periods, future transition costs become more inflated than they are in reality, delaying the transition and sending the wrong signals to policymakers and investors (Polzin et al., 2021; Bachner, Mayer & Steining, 2019). Therefore, WACCs corresponding to the technology used, time period and Slovenian reality need to be applied if I am to estimate cost prices as accurately as possible.

The calculations for coal-fired, gas-fired and hydropower (used as a proxy for pumped storage HPP) plants in Slovenia were based on the results presented by Polzin and co-workers (2021, p. 8). I assumed that WACC for gas-fired power stations will remain the same from 2021 to 2030 due to the interplay of two opposing processes: on the one hand,

neighbouring countries with more optimal conditions for solar or wind power plants (Croatia, Austria, Italy, Western Balkans) could provide cheaper electricity too.

28 Dedicated funds for decommissioning did not exist until 1995. From 1995 to 2020, the expense was 3 EUR/MWh, which increased to 4.8 EUR/MWh in 2021. In the winter of 2021/2022, proposals have been made to increase the amount to 12 EUR/MWh, also due to extremely high electricity prices.

gas-fired power stations could play an essential bridge role and could be upgraded to run exclusively on hydrogen by 2036, which would increase the prospects of the technology and push WACC downward; on the other hand, more ambitious EU climate targets and the risk of fossil fuel-based power plants becoming stranded assets could have a negative effect on their future prospects. Since significant technological development and deployment of pumped storage hydropower plants in Slovenia have not been envisioned, it seemed reasonable to apply the same WACC throughout the observed period (2021, p. 8). Polzin et al. (2021, p. 8) also calculated the WACC for WPPs in 2021. Scenario of derisking policies for renewable energy power plants, presented by Bachner, Mayer and Steining (2019, p. 21), provided WACC for WPPs in 2030. For the 2030–2040 period, I applied a financing experience rate, i.e. the cost of capital decreasing by a constant percentage for each time cumulative technology deployment doubles, of 5.7% (Polzin et al., 2021, pp. 9, 10). As for solar power stations, Bachner, Mayer and Steining (2019, p. 21) estimated a WACC of 3.5% for solar parks in Eastern Europe in 2019 on the assumption of state implementation of derisking policies. This is in line with the findings by the International Energy Agency on the nominal WACC of SPPs in Europe (International Energy Agency, 2020, pp. 234–240). To calculate what WACC solar projects would have in the future, I used a 4.4% learning rate each time installed solar capacities double (Polzin et al., 2021, p. 10), countervailing the gradual decrease in state-supported schemes and an increase in the number of bigger investors with a greater share of equity financing. It is assumed that hydrogen-based power plants will have the same WACC as gas-fired power plants in 2030 since hydrogen-based power stations will be only slightly upgraded gas-fired power plants. The 5% learning rate was employed to calculate their WACC for the year 2040 (Polzin et al., 2021, p. 10). As for electrolysers, their WACC would equal 4.3% in 2030 (ENCO, 2020, p. 52) with the same learning rate as for hydrogen-fired power stations. Battery storage systems had a WACC of 11% in 2021 (Lazard, 2018, p. 11), while the value for 2030 and the financing experience rate are the same as the values for electrolysers. Lastly, Polzin et al. (2021, p. 8) estimated that nuclear power plants in Slovenia would have a WACC of 6.81% in 2015, while the IEA (2020, p. 418) predicted a WACC of 7% for developed countries. Building upon the highly likely assumption of nuclear power being integrated within the EU sustainable finance taxonomy (B.V., 2022), an additional decade of development and commercialisation of GEN III reactors, adequate debt financing through credits and bonds with low-interest rates (Bergant, 2013, p. 16), GEN Energija being state-owned, state backing of the investment and recognising it as strategically important, it seemed realistic to assume a 5% nominal WACC for JEK2. All the more so as a WACC of 3% reflects a "stable market environment with high investment security" (International Energy Agency & Nuclear Energy Agency, 2020, p. 18). In addition, a study prepared for the Dutch government found that a 4.3% WACC for NPPs could be reached if governments implemented risk-sharing instruments (ENCO, 2020, p. 56). Table 60 summarizes nominal WACCs utilised in the cost price calculations, while Table 4 in the Appendix shows all the inputs and sources used.

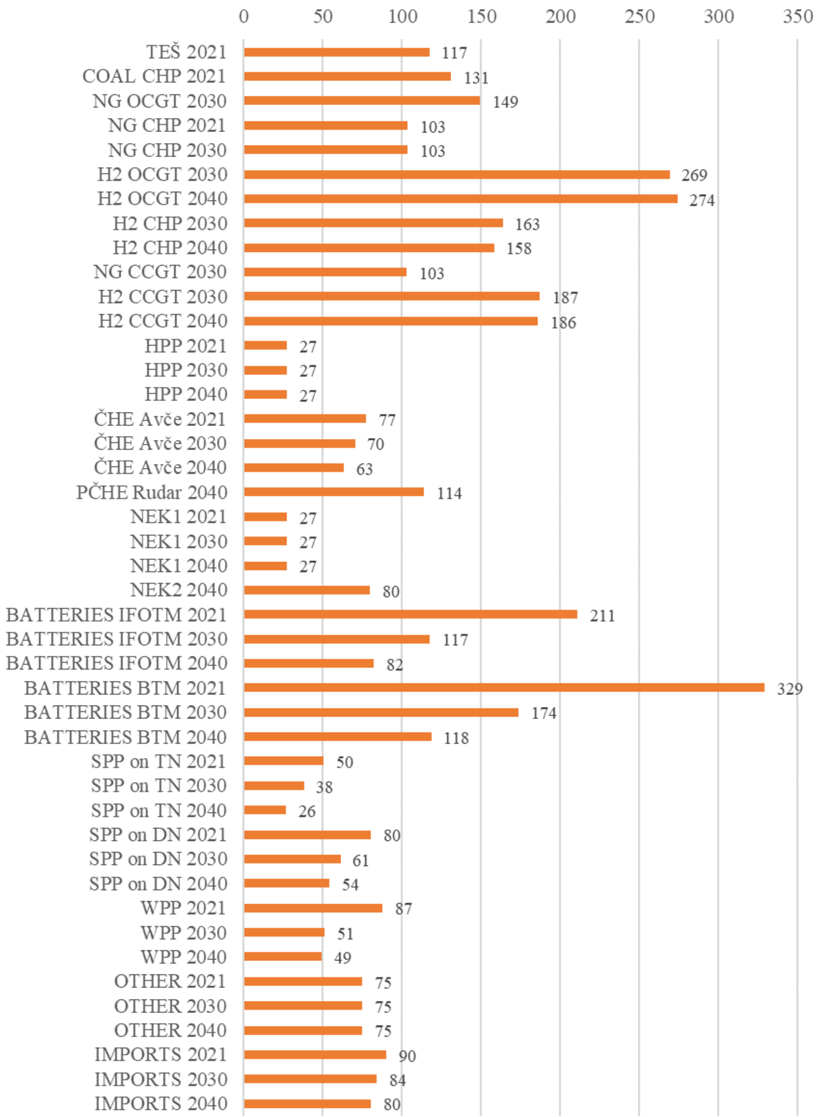
Table 60: Nominal WACCs used in cost price calculations (%)

NOMINAL WACC (%)	2021	2030	2040
COAL CHP	6.69		
NATURAL GAS OCGT	2.73	2.73	
NATURAL GAS CHP	2.73	2.73	
NATURAL GAS CCGT		2.73	
HYDROGEN & SNG OCGT		2.73	2.40
HYDROGEN & SNG CHP		2.73	2.40
NATURAL GAS CCGT		2.73	2.40
(U)PSHPP	5.23	5.23	5.23
JEK2			5.00
BATTERY STORAGE	11.00	4.30	4.12
SPP	3.50	2.96	2.81
WPP	10.60	2.80	2.66
ELECTROLYSERS		4.30	3.49

Source: own work based on Polzin et al. (2021); Bachner, Mayer & Steining (2019); International Energy Agency (2020) and Lazard (2018).

Figure 34 shows the expected cost prices of various power plants throughout the observed period.

Figure 34: Cost prices of various power plants in 2021, 2030 and 2040 (EUR/MWh)



Source: own work based on Fürstenwerth (2014); Pietzcker, Osorio & Rodrigues (2021); Mervar (2014 and 2019a); Žerdin et al. (2021); EEX; EC (2016b and 2020e); ENCO (2020); Egli, Steffen and Schmidt (2019); Polzin et al. (2021) and Bachner, Mayer & Steining (2019).

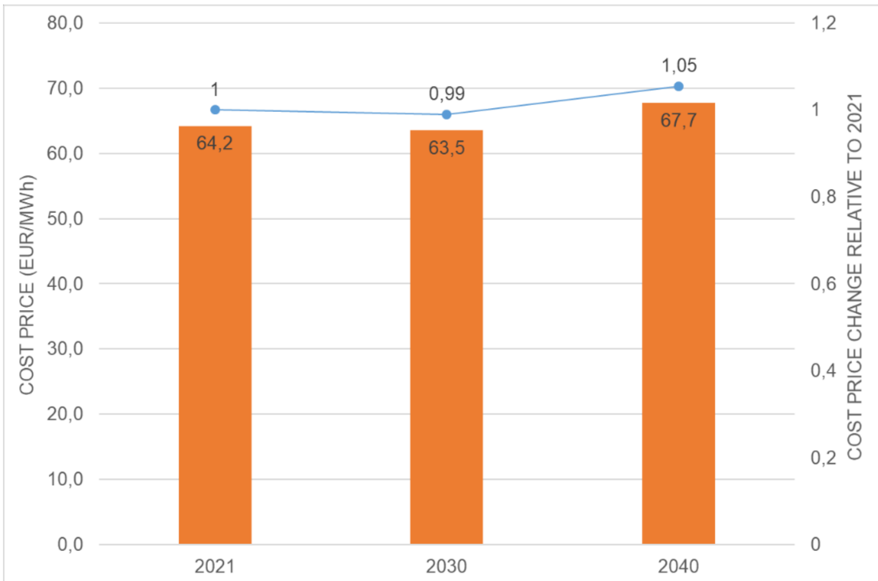
Table 61 and Figure 35 show foreseen weighted cost prices for 2021, 2030 and 2040. Weighted cost prices are first predicted to decrease slightly and then increase – from 64.2 EUR/MWh in 2021 to 63.5 EUR/MWh in 2030 and 67.7 EUR/MWh in 2040. Compared to 2021, cost prices would decrease by 1% by 2030 and increase by 5% by 2040, respectively, which makes the proposed green transition in the electric power sector economically viable and sensible in terms of the cost price.

Table 61: Weighted cost price in 2021, 2030 and 2040 (EUR/MWh)

POWER PLANT/ENERGY SOURCE	COST PRICE (EUR/MWh)			SHARE OF ELECTRICITY GENERATED			WEIGHTED COST PRICE (EUR/MWh)		
	2021	2030	2040	2021	2030	2040	2021	2030	2040
NPPK1	27	27	27	0,20	0,15	0,10	5,4	4,2	2,8
NPPK2			80			0,26			20,7
HPP	27	27	27	0,33	0,25	0,16	8,9	6,8	4,3
COAL TEŠ	117			0,22			25,7		
COAL CHP	131			0,03			3,7		
NG CHP (2021 downward adj.)	103	103		0,02	0,05		1,8	4,9	
NG OCGT (2021 downward adj.)	169,9	149		0,00	0,05		0,6	7,7	
NG CCGT		103			0,07			6,8	
H2&SNG CHP		163	158		0,00	0,04		0,3	5,8
H2&SNG OCGT		269	274		0,00	0,01		0,5	2,5
H2&SNG CCGT		187	186		0,00	0,03		0,4	4,9
SPP ON TN (new)	50	38	26						
SPP ON TN (weighted)	50	43	37	0,00	0,08	0,10	0,0	3,4	3,9
SPP ON DN (new)	80	61	54						
SPP ON DN (weighted)	80	70	64	0,03	0,09	0,11	2,1	6,1	7,3
WPP (new)	87	51	49						
WPP (weighted)	87	66	59	0,00	0,02	0,02	0,0	1,1	1,1
ČHE Avče	77	70	63	0,02	0,01	0,01	1,2	0,9	0,5
PČHE Rudar			114			0,01			1,2
BATTERY - in front of the meter	211	117	82	0,00	0,01	0,01	0,2	1,4	1,1
BATTERY - behind the meter	329	174	118	0,00	0,01	0,01	0,3	2,1	1,6
IMPORTS (2021 downward adj.)	90	84	80,4	0,14	0,16	0,09	12,2	13,1	7,1
OTHER	75	75	75	0,03	0,05	0,04	1,9	3,8	2,9
WEIGHTED COST PRICE							**64,2**	**63,5**	**67,7**
INCREASE RELATIVE TO 2021							**1**	**0,99**	**1,05**

Source: own work.

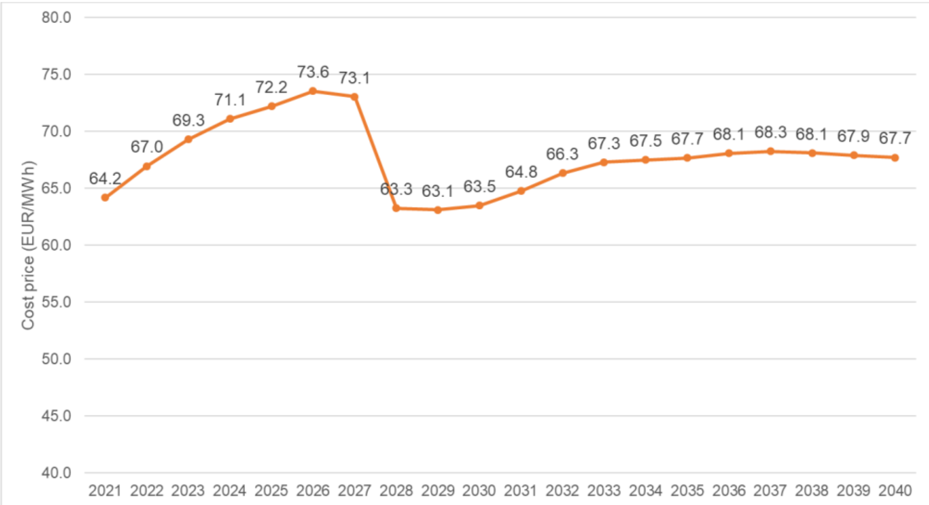
Figure 35: Weighted cost price in 2021, 2030 and 2040 (EUR/MWh)



Source: own work.

Figure 36 presents the predicted annual weighted cost price of electricity from 2021 to 2040. The weighted cost price of electricity is expected to increase until the end of the coal phase-out in TEŠ due to the latter's growing cost prices and then substantially fall below 2021 levels. From 2028 onwards, it is forecasted to gradually increase above 2021 levels due to new, not yet amortized power plants (JEK2), low carbon power plants with higher cost prices (power plants running on hydrogen) and amortized power plants (existing HPPs and NEK1) holding an ever smaller share in relative terms. As can also be seen in Table 62, the foreseen movement is in line with the direction anticipated in the SAZU scenario (SAZU, 2022). Moreover, as my coal phase-out is faster than theirs, the most significant upswing due to TEŠ is shorter (2028 vs 2033).

Figure 36: Weighted cost price of electricity from 2021 to 2040 (EUR/MWh)



Source: own work.

Finally, if we compare the cost prices estimated in the SAZU scenario with mine, some conclusions can be drawn (Table 62). First, the cost prices of both scenarios are similar, underlying the sensibility of my approach. Second, the cost price that they give for 2030 is substantially higher than mine in absolute and relative terms due to the prolonged operation of TEŠ, reinforcing the appropriateness of my coal phase-out path. Last but not least, both proposals show the same relative increase in 2040 compared to 2021.

Table 62: Comparison of weighted cost prices between proposed plan and scenario envisioned by SAZU for 2021, 2030 and 2040

WEIGHTED COST PRICE OF ELECTRICITY	2021	2030	2040
Ostan Ožbolt (EUR/MWh)	64.2	63.5	67.7
Ostan Ožbolt (relative to 2021)	1.00	0.99	1.05
SAZU (EUR/MWh)	59	69	62
SAZU (relative to 2021)	1.00	1.17	1.05

Source: own work and SAZU (2022).

6.3.2 Profit and loss statement of the electric power system in 2021, 2030 and 2040

Profit before tax for the entire electric power system in 2021, 2030 and 2040 is calculated based on the methodology by Mervar (2019a, p. 9) and Babič (internal document) and is shown in Table 63. In contrast to the last few years, when electricity generation was not economical due to low wholesale electricity prices, and the near-future projections were not promising either (Mervar, 2019a, p. 9), my calculations show that earnings before tax would be positive throughout the observed period: they would amount to EUR 319M in 2021, EUR 318M in 2030 and EUR 326M in 2040. Thus, profits are expected to stay more or less the same even though wholesale electricity prices are predicted to diminish.

Table 63: Profit and loss statement of the entire electric power system in 2021, 2030 and 2040

PROFIT AND LOSS STATEMENT OF ELECTRIC POWER SYSTEM	2021	2030	2040
WHOLESALE ELECTRICITY PRICE (EUR/MWh)	90	84	80
WEIGHTED COST PRICE (EUR/MWh)	64.2	63.5	67.7
DIFFERENCE (wholesale – cost price)	26	20	13
GENERATION (GWh)	12,351	15,526	25,726
REVENUE (EUR M)	1,112	1,304	2,068
COSTS AND EXPENSES (EUR M)	793	986	1,742
PROFIT BEFORE TAX (EUR M)	**319**	**318**	**326**

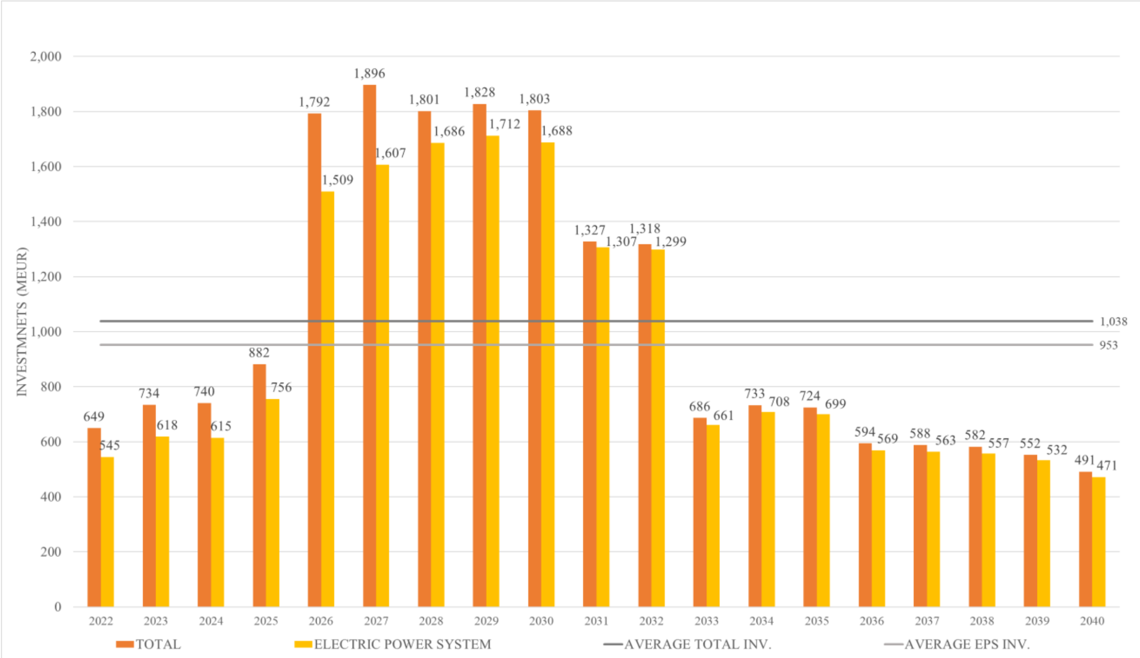
Source: own work based on Mervar (2019a).

6.3.3 Total and annual investment costs

According to my plan, EUR 19,721M of total investments would be required in the 2022–2040 period, translating on an annual basis into EUR 1,038M on average, with a range between EUR 491M to EUR 1,896M. Considering electric power system-related investments (EPS) alone and therefore omitting the socio-economic restructuring plan of the SAŠA region and the funds covering TEŠ losses, but still including the hydrogen storage and transmission costs and half of the expenses for CHP plants, total investments would reach EUR 18,102M over the observed period. In this case, annual expenses would amount to EUR 953M on average and vary from EUR 471M to EUR 1,712M. Figure 37 and Table 64 summarize the data. For more details, see Tables 5 and 6 in the Appendix.

The significant increase in funds required would occur during the seven-year construction period of the JEK2 from 2026 to 2032. This would signify the most intensive part of the investment cycle because of the overlap between the construction of JEK2 and various other projects - the investment in the underground pumped storage HPP Rudar, the building of the electrolyser connected to JEK2, the restructuring plan of PV and TEŠ, the socio-economic restructuring program of the SAŠA region and the investments in renewable energy power plants. Encouragingly, state, regional and private actors would have four years to prepare and set up the conditions for implementing these projects as smoothly as possible.

Figure 37: Annual total and electric power system-related investments from 2022 to 2040 (M EUR; 2020 prices)



Source: own work.

Table 64: Average annual investments, total investments from 2022 to 2040 and comparison with SAZU's calculations (M EUR; 2020 prices)

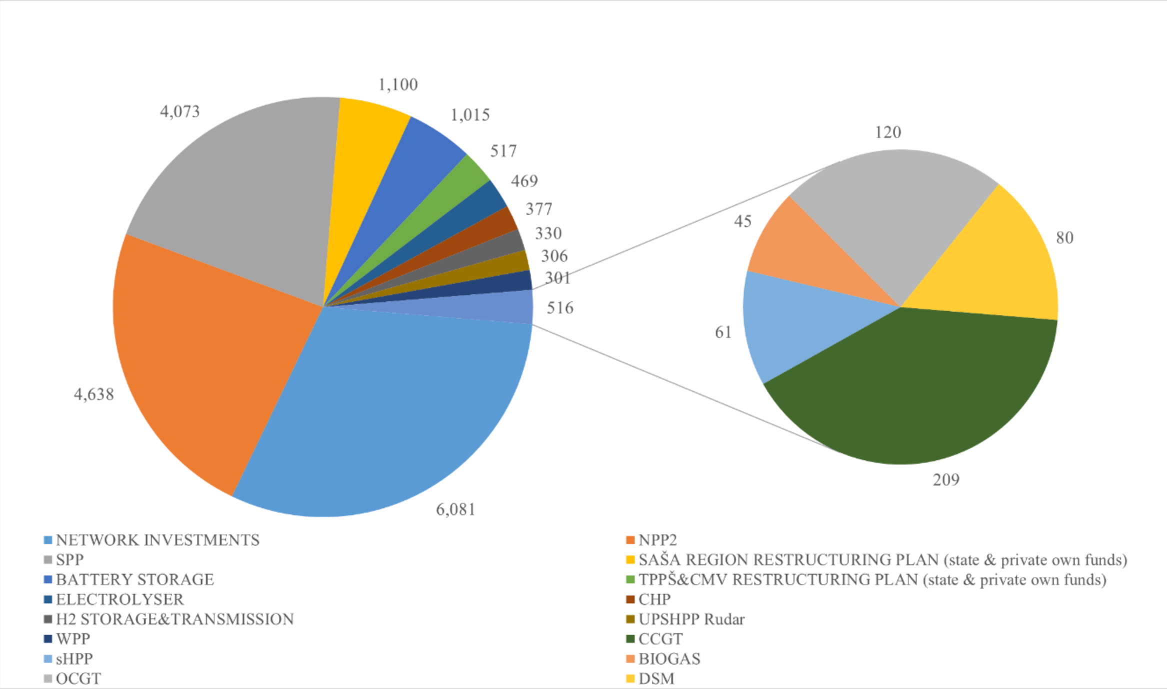
INVESTMENTS (EUR M)	EPS	TOTAL
AVERAGE ANNUAL INVESTMENTS	953	1,038
TOTAL INVESTMENTS	18,102	19,721
SAZU	17,167	

Source: own work and SAZU (2022).

The decarbonisation plan proposed by SAZU (2022) would require EUR 17,167M of investments. The difference between my plan and theirs is roughly 5%, underlying the appropriateness of my approach. Even more so if we take a broader picture: on the one hand, their plan does not include hydrogen storage and transportation, demand-side management expenses and hydrogen-related refurbishment costs, only partly contains investments into the electricity network (EUR 2,276M vs 6,081M) and has some CAPEX assumptions substantially lower than mine (SPP in 2030: 494 vs. 740 EUR/kW on average; batteries in 2030: 500 vs. 1,237 EUR/kW on average). Moreover, as their goal is to decarbonise the whole sector as late as 2050, they reap some benefits of lower investment costs due to the slower rollout of some power plants. On the other, they envision more investments in some power plants than I by which they attain import independence (SPP: 7,680 vs. 6000 MW; JEK2: 1100 MW vs. 880 MW), foresee investments in HPPs that I abstain from and give higher values for some CAPEX assumptions (JEK2: 6000 vs. 5,270 EUR/kW). Therefore, the fact that my proposition is more or less cost-comparable to the only other thorough program evaluating the economic aspect of the transition further proves its economic viability.

Disaggregating total investments by technology and purpose (Figure 38), most funds would be allocated to upgrading the electrical grid, JEK2 and solar parks.

Figure 38: Projected investments by technology and purpose by 2040 (M EUR; 2020 prices)



Source: own work.

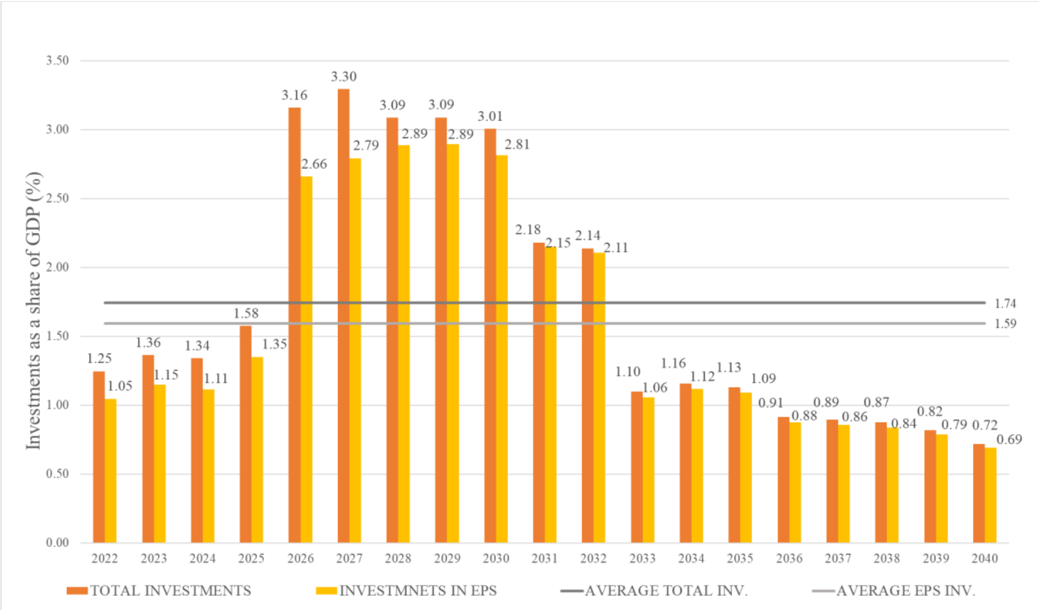
6.3.4 Proposed investments as a share of GDP

Face values do not mean much without context, which is why the projected expenses as a share of future GDP are presented in this subchapter. In the following subchapter, the proposed scenario is then compared to past annual investments.

To obtain real, inflation-adjusted GDP for the future, I increased the nominal GDP of 2020 (Statistični urad, n. d. b) by real GDP growth rates. I used the data published by the Bank of Slovenia (Banka Slovenije, 2021, p. 7) for the period up to 2024, and the reference scenario published by the EC (Capros et al., 2016 in Vlada Republike Slovenije, 2020, p. 119), also used in the NECP, for the period after 2024. These values are similar to those published by IEA (2020, p. 79). However, as the EC scenario has underestimated the real GDP growth rates for every single year since 2016 (Vlada Republike Slovenije, 2020, p. 119) and as the expected real growth rates, ranging from 1.2% to 1.4%, are relatively low considering historical data, the obtained shares of the proposed investments in future GDP are presumably near the upper bound.

As seen in Figure 39 and Table 65, total foreseen investments average 1.74% of GDP and range from 0.72 to 3.30% of GDP throughout the observed period. Considering the electric power system alone, the expenses are expected to amount to 1.59% of GDP on average and vary from 0.69% to 2.89% of GDP from 2022 to 2040.

Figure 39: Proposed investments as a share of GDP from 2022 to 2040 (%)



Source: own work.

Table 65: Proposed average investments as a share of GDP 2022–2040 (%)

INVESTMENTS AS A SHARE OF GDP	EPS	TOTAL
PROPOSED INV. 2022–2040 (%)	1.59	1.74

Source: own work.

6.3.5 Proposed investments relative to past annual investments

This subchapter will be dedicated to a comparison between projected expenditures and average past annual investments in the electric power system from 2010 to 2019 (Statistični urad, n. d. c). Past expenditures in tangible goods, intangible fixed assets and concessions amount to EUR 476M per year (at 2020 prices), whereas planned annual expenditure amount to EUR 953M, representing exactly 100% increase or an additional EUR 477M per year (Table 66). This means that state, private and local actors should spend an additional 0.80% of GDP annually on electric power system-related matters throughout the 2022–2040 period. Moreover, the ratio between the proposed and business-as-usual (BAU) scenarios for the

2021–2030 period is more than 2.28, whereas the ratio between the envisioned and NECP scenarios for the same era amounts to 1.67, underlying the need for much more action and investments in the electric power system over this decade (Vlada Republike Slovenije, 2020, p. 216). However, we need to bear in mind that under my plan, 60% more funds would be spent in this decade compared to the next decade, thus lowering the ratio over the whole period.

Table 66: Average annual proposed investments, past expenses and BAU and NECP scenarios (2020 prices)

INVESTMENTS IN ELECTRIC POWER SYSTEM	
Past annual investments 2010–2019 (EUR M)	476
Proposed annual inv. 2022–2040 (EUR M)	953
Ratio proposed vs. past investments	2.00
Additional investments required (EUR M)	477
Additional inv. required as a share of GDP (%)	0.8 %
BAU scenario 2021–2030 (EUR M)	4,700
NECP scenario 2021–2030 (EUR M)	6,444
Proposed scenario 2022–2030 (EUR M)	10,735
Ratio proposed vs. BAU scenario	2.28
Ratio proposed vs. NECP scenario	1.67

Source: own work based on Vlada Republike Slovenije (2020) and Statistični urad (n. d. c).

Even though the increase in past annual investments by EUR 477M (a 100% increase or an additional 0.8% of GDP) seems relatively substantial, it is in line with similar studies (the EC predicts an even larger increase (Darvas & Wolff, 2021, p. 6)) and, judging by the ten factors presented below, is realizable. First, in the 2010–2019 period, investments in the electricity, gas, steam and air conditioning supply represented only roughly 6% of the total gross capital formation on average (Statistični urad, n d. d). Second, the wave of investments described above would unfold simultaneously with a withdrawal of funds for fossil fuel-based projects. Such a setting would provide additional space and facilitate the execution of green projects. Third, the share of total gross fixed capital formation in Slovenian GDP has been below the EU average since 2011 (Eurostat, 2021), primarily due to low private sector investments (Brložnik, 2021, p. 5). Private and public green expenditures could reverse the negative trend and thereby help Slovenia catch up with the most advanced economies. Even more so as IRENA, European Investment Bank and World Economic Forum expect that the ratio of public to private investments for the green transition will vary from 1:4 to 1:5 (Darvas & Wolff, 2021, p. 5). Fourth, in the last ten years, gross fixed capital formation had a slightly negative contribution to GDP volume growth (UMAR, 2021, p. 110). My strategy can thus mark a turning point. Fifth, various respected institutions have raised concerns about Slovenia's lack of green investments and the urgency to increase them (UMAR, 2021, p. 110). Sixth, the green transition represents one of the core Slovenian and EU development goals (UMAR, 2021, p. 110). Therefore, future EU, state and private endeavours, capacities and resources will be expanded regardless of my program. Seventh, European policymakers have recently begun to discuss whether and how to modify the existing fiscal rules to consolidate the budget and simultaneously accelerate the actions needed to reach core EU goals, especially the green transition and digitalisation (Draghi & Macron, 2021). The "green golden rule", under which net green investments would be excluded from the fiscal indicators used to measure fiscal rule compliance, and other solutions have been proposed (Darvas & Wolff, 2021; Damijan, 2021). The expected new fiscal framework, EU taxonomy for sustainable activities, The European Green Deal Investment Plan and Next Generation EU programme will significantly enhance and streamline green investments. Eighth, until recently, investments in the electric power system were almost exclusively confined to a limited number of energy companies, but new technologies and policies have broadened the scope of investors. I believe that a considerable share of batteries, SPPs, WPPs, demand-side management and other small- to medium-scale technologies will be owned by households, local communities, enterprises and other actors, pouring additional capital into the electric power system. Importantly, in 2020, household deposits in Slovenia were at a record EUR 23 billion (Slovenian Times, 2021). These players will finance such technologies directly (i.e. SPPs on the rooftops of houses or warehouses) and indirectly (i.e. the expanding green bonds market or various investment funds using environmental, social and governance (ESG) criteria to support green projects). Note also the ratio of public to private investments mentioned above. Ninth, the green transition is an extraordinary opportunity for Slovenia because it could bring many benefits. On the national level, these include net employment creation (e.g. UNIDO & GGGI, 2015), new industrial opportunities, improved health, more cohesive communities and nature conservation, and on the global level, Slovenia could contribute to the prevention of conflicts and habitat destruction worldwide. On top of that, as the climate crisis "poses an existential threat to humanity" (United Nations, 2018), the question is not whether we respond, but how and when we should do so.

CONCLUSION: ASSESSING THE HYPOTHESES

My hypotheses were:

1. There exists at least one viable decarbonisation path for the Slovenian electric power system that is in line with the five main pillars: reliability and security of supply; the economics of electricity generation; social justice of the transition; nature conservation; and compliance with the Paris Agreement.
2. The proposed decarbonisation plan is economically feasible, in the sense that coal phase-out will happen when comparable power plants reach lower cost prices; future weighted electricity cost prices will increase marginally, at worst, compared to 2021 and be in line with the SAZU study; estimated future profits before tax of the whole electric power system will, at worst, stay the same compared to 2021; projected total investments will be viable throughout the 2022–2040 period and comparable to the SAZU study; and lastly, predicted yearly investments will be in line with other

analyses and present a reasonable and manageable rise compared to the past expenditures.

Regarding the first hypothesis, in my plan reliability of supply is secured through significantly greater aFRR capacities on disposal than required (subchapter 5.7) and only a slight increase in mFRR easily covered by European and national possibilities (subchapter 5.8). Security of supply is accomplished through safe coverage of peak load (subchapter 5.6), import dependence significantly below the admissible threshold (subchapter 6.1), adequate capacities for tackling surplus solar power output (subchapter 5.1) and sufficient strategic reserves for winter and summer (subchapter 5.5). Both reliability and security of supply are additionally strengthened through a comprehensive restructuring plan of TEŠ and PV, by which coal phase-out is delayed for two years (subchapter 3.2). These objectives are also accomplished by means of significant investments in transmission and distribution networks, building upon data from ELES and SODO (subchapter 5.9), as well as seasonal hydrogen storage in Eastern Slovenia (subchapter 5.4.5). Lastly, the balanced future structure of energy sources, where no single energy source or power plant would hold an outsized role in a system (subchapter 6.1), and a sensible interconnection between electricity and heating sectors (subchapter 4.4) provide additional robustness to the system.

I examined the economics of electricity generation by seeking the most cost-effective coal phase-out (subchapter 3.2), a sensible mix of new power plants with reasonable cost prices and system costs (chapter 4), and by choosing cheaper types of same technology (e.g. utility-scale PPs instead of smaller ones, alkaline electrolysers rather than PEM ones, demand-side management) (chapters 4 and 5). It seems that I have achieved my goal because at the time of the coal phase-out, the cost prices of comparable power plants are expected to be lower than TEŠ's, and the operation of TEŠ would be extended for only two years (subchapter 3.2). Only a slight increase (5%) in weighted electricity cost price is foreseen by 2040 compared to 2021 (subchapter 6.3.1), marking the exact same rise as predicted in the SAZU scenario. The profit before tax of the electric power system as a whole is expected to be positive and more or less the same as in 2021 (subchapter 6.3.2), projected total investments are comparable to similar studies (subchapters 6.3.3 and 6.3.4), and the growth of predicted annual investments in relation to past expenses is manageable and in line with EC estimations (subchapter 6.3.5).

The social pillar is ensured on the international level by a timely decarbonisation plan (subchapter 6.2), on the national level by only a slight increase in cost prices throughout the observed period (subchapter 6.3.1) as well as a democratisation of the electricity sector through some installed wind capacities and a fifth of all installed solar capacities owned by communities or households (e.g. subchapters 4.1 and 4.2), and on the regional level by a postponed closure of TEŠ and PV, secured with sufficient public and private funds, and a just socio-economic restructuring of the entire Šaleška valley (subchapter 3.2). Moreover, new energy projects in the Zasavje region also contribute in this respect (e.g. subchapters 4.6 and 5.4).

I have shown that additional biodiversity loss and destruction of nature could be prevented by applying rigorous nature conservation decisions based on numerous studies, such as foregoing new big HPPs (subchapter 4.3.2), new biomass-fired CHP plants (subchapter 4.4) and ČHE Kozjak (subchapter 4.5), while deciding for a new nuclear power plant (subchapter 4.8), PČHE Rudar within Coal mine Velenje (subchapter 4.5) and SPPs on appropriate locations (subchapter 4.1). Go-to areas are employed for locating WPPs (subchapter 4.2) and sHPPs (subchapter 4.3.3) on non-contested sites. The prevalence of the public interest of electricity generation over nature conservation is not expected or applied. In addition, I have envisioned measures to rewild rivers into their natural, free-flowing state, decommission the most harmful sHPPs and remove the related dams (subchapter 4.3.3).

Lastly, I have failed to reach the short-term objective of a 68% reduction in GHG emissions by 2030 compared to 2020. However, my plan does meet the demand made by the United Nations of cutting emissions in half by the end of this decade and considerably exceeds Slovenian and European targets. I have also attained the long-term goal of reaching net-zero carbon emissions in the electric power system before 2040 (i.e. around 2036), using life-cycle greenhouse gas emissions of various energy sources (subchapter 6.2).

Considering the above, I can conclude that my plan is in accord with the five main pillars, i.e. reliability and security of supply, economics of electricity generation, social justice of the transition, nature conservation and compliance with the Paris Agreement, by which the first hypothesis is confirmed. The economic reasoning presented above also confirms the second hypothesis.

Suppose we, as the next step, reflect on my plan in relation to the SAZU scenario, the only other complete publicly available decarbonisation scenario prepared by electrical engineers, economists, biologists and other members of the Slovenian Academy of Sciences and Arts (SAZU, 2022). In that case, it can be said that both scenarios are in agreement in all crucial aspects except the date of the coal phase-out and that the remaining differences are not predominantly technical or economic but mainly related to biodiversity. Both plans see solar power and nuclear power as the two most important pillars of future decarbonisation of the Slovenian electric power system, accompanied by some wind power plants, combined cycle gas turbines, combined heat and power plants and a few other types of power plants. CCGTs and CHP plants would first run mainly on natural gas (in their case, also on biomass) and then gradually shift to zero- or low-carbon hydrogen and synthetic natural gas. Additionally, as shown in subchapters 6.3.1 and 6.3.3, estimated future weighted electricity cost price and total investment costs of the two scenarios are comparable, the only exception being the fall in weighted cost price due to coal phase-out. As SAZU's coal phase-out is later than mine (2033 vs 2028), the estimated reduction is five years faster in my scenario. Such a proposition has significant economic and climate-related implications. While GHG emissions would be more than halved by 2030 in my plan, the SAZU scenario predicts emissions will remain higher in 2033 compared to 2021 and substantially decline only after the closure of TEŠ6. Another noteworthy difference relates to hydropower plants and biomass power plants. Since my program gives equal importance to all five pillars, including biodiversity, new big hydropower and biomass power plants are not pursued. The SAZU scenario (not considering comments from biologists from the National Institute of Biology) foresees four new hydropower plants (not more due to objections from biologists) and additional biomass usage. Mine and the SAZU scenario would thus lead to divergent outcomes regarding the state of the biodiversity and conservation of nature in Slovenia. Another disparity or, rather, a task for the future in both scenarios stems from their different focus. In my programme, I have tried to cover all five pillars with the intention to provide the initial step towards finding common ground for multiple stakeholders, initiate multidisciplinary research and thus facilitate and accelerate the decarbonisation of the Slovenian electric power system. With such a holistic approach, some aspects can only be covered partially. In contrast, the SAZU scenario lacks a social component, focuses less on biodiversity issues and reduces GHG emissions more slowly. On the other hand, the technical aspect of the SAZU scenario goes more in-depth than mine as it examines the production and consumption for each hour in a year, whereas my hourly calculations have been done for the two most crucial periods within a year and some other distinct days.[29] All in all, at the strategic level, both scenarios show a common way forward. They underline the two most promising energy sources for decarbonising the Slovenian electric power system on which we should focus – solar power and nuclear power.

As already mentioned, the technical part, where the SAZU scenario tests the proposed development of the electric power system on an hourly basis for the whole year, presents a future challenge for my plan. However, this aspect isn’t the only future task to deepen my strategy. In the technical aspect, it could be improved by evaluating additional performance indicators of the reliability of supply (voltage stability, N-1 criteria etc.) and providing insights into what it would mean for the envisioned electric power system if the construction of some suggested power plants (especially JEK2) were delayed. As for economic aspects, sensibility analysis for various most salient features (investment cost for JEK2, WACC of JEK2, price of electricity etc.) would provide additional context and make the plan more robust against unexpected changes (e.g. exceptionally high electricity prices during the winter of 2021/2022). Reflecting on the effects of the program on inflation, identifying state, private and EU funds available for the implementation of the proposed plan and additional funds required (see Brložnik, 2022), delineating policies to obtain these resources and, last but not least, providing some argumentation as to why and how to secure funding for decarbonisation amidst looming fiscal consolidation and higher interest rates (see Darvas & Wolff, 2021) would deeply enrich the work. Another crucial future challenge would be to estimate the employment multipliers of various energy sources and net job gains (see Pollin, Garrett-Peltier, Heintz & Hendricks, 2014). Such calculations would be paramount to gaining broader support among the public, trade unions and workers, accelerating the transition. Besides the results on the net jobs gains and employment multipliers, social aspects would be improved if measures for a just transition in the SAŠA region and policies

[29] However, I have also provided estimations on the future state of aFRR and mFRR.

for securing a just and worker-friendly green path on the national level, where the main polluters would bear the brunt of the costs, would be stipulated. Lastly, environmental facets of the master's thesis could be deepened in various ways, especially by updating the existing maps that identify environmentally acceptable potential of wind power plants, preparing new maps with suitable areas for building big solar power plants and, lastly, developing a methodology for life-cycle analysis of adverse effects of different power plants, batteries, electrolysers and other energy-related infrastructure on the environment. With the help of such methods – especially since electrolysers and batteries are a necessary companion of solar power plants, but the scientific data on their damaging effects is inconclusive – it would be musch easier to choose the most optimal option among different power plants (e.g. between hydropower plants on the one hand and solar power plants, batteries and electrolysers on the other).

Building upon these future scientific challenges, I hope that my interdisciplinary scenario, incorporating a broad spectrum of diverse positions and scientific findings will, firstly, initiate, fasten and direct the future scientific work of experts from multiple fields to prepare a comprehensive decarbonisation plan of the Slovenian electric power system in line with at least the five presented pillars and, secondly, lay the foundations for an honest discussion between (often conflicting) stakeholders. If all agents strive for the common good, listen to each other and base their reasoning on scientific evidence, the result of both, scientific and political, interconnected processes will be a thorough plan acceptable to most parties involved. Consequently, such a program will gain broad support, bring about multiple benefits to each and every one, accelerate the transition and effectively tackle the climate crisis in a socially, economically, technically and environmentally sensible way.

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APPENDICES

Appendix 1: Povzetek (Summary in Slovene language).

Slovenski elektroenergetski sistem (EES) je pred zahtevnim rebusom – zaradi podnebne krize ter z njo povezanih mednarodnih in evropskih podnebnih zavez mora pospešeno preiti na nizkoogljične vire energije. Kot da to ne bi bilo dovolj zagonetno, proces razogljičenja ne sme poslabšati tehničnih in ekonomskih parametrov delovanja sistema, poglobiti socialnih stisk ter pospešiti upada b iotske raznovrstnosti. Še več, da bi ga podprla najširša množica naravoslovnih in humanističnih strokovnjakov, nevladnih organizacij, civilnih iniciativ in ljudskih množic, kar predstavlja predpogoj njegove implementacije, mora obsegati najrazličnejša področja in znanja različnih strok. Konkretno, vsak celovit in tehten plan razogljičenja EES mora biti skladen s petimi krovnimi stebri: zanesljivo in sigurno obratovanje EES; ekonomičnost delovanja; socialna pravičnost; ohranjevanje narave; in usklajenost s Pariškim podnebnim sporazumom.

Zanesljivost delovanja je v magistrski nalogi zagotovljena z dovoljšnimi kapacitetami avtomatske rezerve za povrnitev frekvence, ki bodo občutno presegle potrebe do leta 2040, ter zanemarljivim povišanjem ročne rezerve za povrnitev frekvence z več kot dovoljšnimi evropskimi in slovenskimi viri za njeno pokritje. Po drugi strani je sigurnost delovanja EES zajamčena z varnim pokrivanjem konične obremenitve, letne uvozne odvisnosti občutno pod najvišjo dopustno mejo, ustreznimi kapacitetami za spopadanje s presežno močjo sončnih elektrarn ter dovoljšnimi strateškimi rezervami za zimske in poletne dni. Celovit plan prestrukturiranja Termoelektrarne Šoštanj (TEŠ) in Premogovnika Velenje (PV), ki njuno (premogovno) obratovanje podaljša za dve leti, bi dodatno prispeval k sigurnemu in zanesljivemu delovanju sistema. Enako velja za obsežne investicije v prenosno in distribucijsko omrežje, večje skladišče vodika na vzhodu Slovenije ter smiseln preplet EES s sektorjem ogrevanja in hlajenja. Nenazadnje, uravnotežena struktura proizvodnje skozi celotno obdobje 2022–2040, ki ne temelji prekomerno niti na enem viru niti na enem samem postrojenju, daje sistemu dodatno robustnost.

Ekonomičnost proizvodnje v magistrski nalogi zasledujemo z iskanjem najbolj stroškovno učinkovitega izhoda iz premoga ter smiselnega prepleta energetskih virov z zmernimi stroškovnimi cenami in razumnimi sistemskimi stroški ter z izborom tistih tipov tehnologij (npr. večje elektrarne in baterije, cenejši alkalijski elektrolizerji, upravljanje s porabo), ki so cenejši od drugih oblik istih tehnologij. Skladnost z ekonomskim stebrom plana smo dokazali z več metrikami. Stroškovne cene električne energije primerljivih elektrarn naj bi bile ob izhodu iz premoga nižje kot pri TEŠ ter državna pomoč bi bila potrebna zgolj za dve leti. Ponderirana stroškovna cena električne energije naj bi leta 2030 in 2040 padla za 1% oz. se dvignila za 5% glede na leto 2021, kar je skladno z izračuni do sedaj najbolj celovitega scenarija razogljičenja, pripravljenega s strani strokovnjakinj in strokovanjkov znotraj skupine na Slovenski Akademiji Znanosti in Umenosti (SAZU). Pričakovani dobiček pred davki celotnega EES naj bi bil pozitiven skozi celotno opazovano obdobje ter leta 2030 in 2040 na ravni tistega iz 2021. Predvidene kumulativne investicije so skladne s študijo SAZU, letni investicijski stroški pa naj bi bili uresničljivi skozi celotno obdobje 2022–2040. Slednje izhaja iz dejstva, da so izračunane letne investicije obvladljive v primerjavi z investicijami preteklih let in v sozvočju z izračuni Evropske komisije.

Socialna podstat programa je izpolnjena na vseh treh ravneh: na globalni ravni s pravočasnim razogljičenjem EES; na nacionalni ravni z zanemarljivim povečanjem stroškovnih cen električne energije ter demokratizacijo energetskega sektorja oz. prenosom dela moči v roke skupnosti in posameznic/posameznikov; na regionalni ravni pa z dovoljšnimi javnimi in zasebnimi sredstvi za celovito in pravično socio-ekonomsko prestrukturiranje Šaleške doline ter podaljšanjem obratovanja PV in bloka 6 TEŠ. Poleg tega nove energetske investicije v Zasavje prispevajo k zagotavljanju pravičnosti predlaganega programa.

Predvideli smo več načinov za preprečevanje nadaljnje degradacije narave, dodatnega upada biodiverzitete in fragmentacije habitatov. Zaradi prekomernih negativnih posledic na naravo nove velike hidroelektrarne in elektrarne na biomaso niso predvidene, medtem ko je izgradnja druge jedrske elektrarne v Krškem biodiverzitetno smiselna. Strokovne študije in iz njih izhajajoča primerna območja (GO-TO lokacije) določajo izbor naravni prijaznih lokacij za prostorsko umestitev vetrnih elektrarn in malih hidroelektrarn, velik pomen varovanju narave pa je dan tudi pri postavitvi sončnih elektrarn. Uporaba postopka prevlade javne koristi proizvodnje električne energije nad ohranjanjem narave ni predvidena. Zaradi prekomernega vpliva na naravo je predlagana zamenjava izgradnje ČHE Kozjak s podzemno ČHE v jamskih prostorih Premogovnika Velenje. Nenazadnje, v želji po renaturaciji in podivljanju vodnih ekosistemov, izhajajoč tudi iz Strategije EU za biotsko raznovrstnost do leta 2030, je predvideno odstranjevanje najbolj škodljivih malih hidroelektrarn s priležnimi jezovi.

Skladnost predlaganega načrta s Pariškim podnebnim sporazumom smo ocenili na kratki in dolgi rok. Kratkoročnega cilja znižanja toplogrednih plinov (TGP) za 68 % do leta 2030 glede na leto 2020 nismo dosegli, vendar je naš plan vseeno skladen s predlogom Združenih narodov, izhajajočim iz Pariškega sporazuma, po razpolovitvi emisij do 2030 glede na 2020, ter občutno presega evropske in nacionalne podnebne cilje do leta 2030. Z doseganjem ničogljičnih emisij do okoli leta 2036 plan doseže dolgoročne cilje Pariškega sporazuma.

Predlagani načrt razogljičenja slovenskega EES je tako skladen z vsemi petimi stebri. Še več, takšen pristop naslavlja enega osrednjih problemov prihajajoče zelene tranzicije: manko skupnega in strokovnega plana razogljičenja EES, ki bi ga podprli tako naravoslovni in humanistični strokovnjaki kot nevladne organizacije, lokalne skupnosti, sindikati in širše ljudske množice. S celovito obravnavo ter vključevanjem pogledov različnih akterjev lahko predstavljeni program nudi osnovno za pogovore med mnogoterimi deležniki in oblikovanje skupnega programa, ki ne bo sprožal nepotrebnih konfliktov in bo pospešil razogljičenje elektroenergetskega sektorja v Sloveniji.

Appendix 2: Electricity balance: generation by power plant, consumption and import dependence from 2022 to 2040 (GWh).

GENERATION BY POWER PLANT (GWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
GENERATION ON TN	**11,393**	**10,880**	**11,458**	**11,686**	**11,814**	**11,665**	**12,002**	**12,439**	**11,439**	**11,809**	**11,900**	**12,135**	**12,677**	**19,012**	**19,247**	**19,482**	**19,608**	**19,628**	**19,755**	**19,882**	**20,008**	**22,217**	**22,344**	**22,470**	**21,728**
COAL/NG TPP	3,965	3,452	3,836	3,836	3,736	3,246	3,246	2,746	646	646	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474
of this TEŠ	3,640	3,127	3,200	3,200	3,100	2,600	2,600	2,100																	
of this TETOL	325	325	636	636	636	646	646	646	646	646	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474
NPP	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	10,172	10,172	10,172	10,172	10,172	10,172	10,172	10,172	12,253	12,253	12,253	11,491
of this NEK1 (50%)	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	
of this JEK2 (80%)														7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328
SMR																						2,082	2,082	2,082	4,163
Big HPP	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,175	4,175	4,175	4,175	4,175	4,175	4,175	4,068	4,068	4,068	4,068	4,068	4,068	4,068	3,961
ČHE Avče & PČHE Rudar	226	226	226	226	226	226	226	226	226	226	226	226	533	533	533	533	533	533	533	533	533	533	533	533	533
SPP	9	9	129	249	369	489	685	880	1,076	1,272	1,467	1,638	1,810	1,981	2,152	2,323	2,445	2,568	2,690	2,812	2,935	3,057	3,179	3,301	3,424
WPP	0	0	0	31	63	94	125	156	188	219	250	287	324	361	398	435	435	435	435	435	435	435	435	435	435
OCGT (NG&H2&SNG)	53	53	120	188	255	394	477	661	758	874	990	990	990	262	262	262	262	262	262	262	262	262	262	262	262
CCGT (NG&H2&SNG)			0	0	0	0	0	500	1,249	1,249	1,249	1,249	1,249	749	749	749	749	749	749	749	749	749	749	749	749
BATTERIES	13	13	20	29	38	90	116	143	170	197	224	251	277	304	331	358	362	367	371	376	380	385	389	394	398
GENERATION ON DN	**1,472**	**1,472**	**1,568**	**1,672**	**1,776**	**1,923**	**2,218**	**2,513**	**3,036**	**3,331**	**3,626**	**3,877**	**4,128**	**4,378**	**4,629**	**4,880**	**5,048**	**5,215**	**5,382**	**5,550**	**5,717**	**5,856**	**5,994**	**6,133**	**6,272**
SPP	371	371	413	454	495	536	751	966	1,180	1,395	1,609	1,797	1,985	2,172	2,360	2,548	2,682	2,816	2,950	3,084	3,219	3,353	3,487	3,621	3,755
WPP	5	5	5	11	16	22	27	33	38	44	50	57	64	72	79	86	86	86	86	86	86	86	86	86	86
Small HPP	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383
CHP plant (excl. TETOL)	499	499	535	570	606	642	677	713	976	1,011	1,047	1,067	1,087	1,107	1,127	1,147	1,167	1,187	1,207	1,227	1,247	1,247	1,247	1,247	1,247
BIOGAS PP	97	97	109	122	134	147	160	172	185	197	210	219	228	237	246	254	263	272	281	290	299	299	299	299	299
OTHER	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
BATTERIES	13	13	20	29	38	90	116	143	170	197	224	251	277	304	331	358	362	367	371	376	380	385	389	394	398
TOTAL GENERATION	**12,864**	**12,351**	**13,026**	**13,358**	**13,590**	**13,588**	**14,220**	**14,952**	**14,475**	**15,140**	**15,526**	**16,012**	**16,805**	**23,390**	**23,876**	**24,362**	**24,656**	**24,843**	**25,137**	**25,431**	**25,726**	**28,073**	**28,338**	**28,603**	**27,999**
DIRECT CONSUMPTION (incl. losses)	**14,253**	**14,253**	**14,620**	**14,914**	**15,209**	**15,723**	**16,090**	**16,457**	**16,824**	**17,191**	**17,557**	**17,907**	**18,256**	**18,605**	**18,954**	**19,303**	**19,331**	**19,359**	**19,387**	**19,414**	**19,442**	**19,502**	**19,562**	**19,622**	**19,681**
CONSUMPTION BY BATTERY STORAGE	30	30	45	65	85	199	259	318	378	438	497	557	617	676	736	796	806	815	825	835	845	855	865	875	885
CONSUMPTION BY ELECTROLYSERS						26	87	147	208	268	329	605	881	3,567	3,982	4,396	5,106	5,816	6,526	7,236	7,945	8,343	8,760	9,198	9,658
FINAL DIRECT&INDIRECT CONSUMPTI	**14,282**	**14,282**	**14,665**	**14,979**	**15,293**	**15,949**	**16,436**	**16,922**	**17,409**	**17,896**	**18,383**	**19,068**	**19,753**	**22,848**	**23,671**	**24,494**	**25,242**	**25,990**	**26,738**	**27,485**	**28,233**	**28,700**	**29,187**	**29,695**	**30,224**
IMPORTS	1,418	1,931	1,639	1,621	1,703	2,360	2,216	1,970	2,935	2,756	2,857	3,056	2,948	-542	-204	133	586	1,147	1,600	2,054	2,507	627	849	1,091	2,225
SHARE OF IMPORTS	0.10	0.14	0.11	0.11	0.11	0.15	0.13	0.12	0.17	0.15	0.16	0.16	0.15	-0.02	-0.01	0.01	0.02	0.04	0.06	0.07	0.09	0.02	0.03	0.04	0.07
IMPORT DEPENDANCE (%)	**10**	**14**	**11**	**11**	**11**	**15**	**13**	**12**	**17**	**15**	**16**	**16**	**15**	**-2**	**-1**	**1**	**2**	**4**	**6**	**7**	**9**	**2**	**3**	**4**	**7**

Source: own work.

Appendix 3: Generation by energy source and imports from 2022 to 2040 (GWh).

GENERATION BY ENERGY SOURCE (GWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
COAL	4,061	3,535	3,456	3,449	3,339	2,821	2,808	2,293	188	164	0										
of this TEŠ	3,640	3,127	3,200	3,200	3,100	2,600	2,600	2,100													
of this TETOL	292	292	145	145	145	138	138	138	138	138											
of this CHP other	130	117	111	104	95	83	70	56	51	26	0										
NATURAL GAS	300	300	846	933	1,019	1,178	1,266	1,939	2,920	3,092	3,041	2,956	2,868	657	504	345	70	0	0	0	0
of this CHP (incl. TETOL)	247	247	726	745	764	786	798	810	958	969	876	855	834	428	357	284	70	0	0	0	
of this OCGT	53	53	120	188	255	392	468	645	736	845	953	921	888	0				0		0	
of this CCGT			0	0	0	0	0	484	1,226	1,279	1,212	1,180	1,146	229	146	61	0	0	0	0	0
NUCLEAR ENERGY	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	10,172	10,172	10,172	10,172	10,172	10,172	10,172	10,172
of this NEK1	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844	2,844
of this JEK2														7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328
HYDROPOWER	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,784	4,784	5,091	5,091	5,091	5,091	5,091	4,984	4,984	4,984	4,984
of this BIG HPP	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,282	4,175	4,175	4,175	4,175	4,175	4,175	4,175	4,068	4,068	4,068	4,068
of this ČHE&PČHE	226	226	226	226	226	226	226	226	226	226	226	226	533	533	533	533	533	533	533	533	533
of this SMALL HPP	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383
SOLAR ENERGY	380	380	542	703	864	1,026	1,436	1,846	2,256	2,666	3,077	3,435	3,794	4,153	4,512	4,871	5,128	5,384	5,640	5,897	6,153
WIND ENERGY	5	5	5	42	79	116	152	189	226	263	300	344	388	433	477	521	521	521	521	521	521
BIOMASS	187	187	187	187	187	187	187	187	187	187	187	153	153	153	153	153	153	153	153	153	153
of this BIOMASS PP	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
of this CHP (incl. TETOL)	84	84	84	84	84	84	84	84	84	84	84	50	50	50	50	50	50	50	50	50	50
BIOGAS	97	97	109	122	134	147	160	172	185	197	210	219	228	237	246	254	263	272	281	290	299
BATTERIES	27	27	40	58	76	179	233	286	340	394	448	501	555	609	662	716	725	734	743	752	761
HYDROGEN & SYNTHETIC NG						8	27	47	68	89	111	208	308	1,303	1,468	1,639	1,926	2,008	2,020	2,032	2,044
OTHER (incl. CHP plants on RES and alt. sources w/o biomass)	71	84	105	129	155	191	215	256	368	351	524	567	575	583	591	599	607	615	623	631	639
TOTAL GENERATION	12,864	12,351	13,026	13,358	13,590	13,588	14,220	14,952	14,475	15,140	15,526	16,012	16,805	23,390	23,876	24,362	24,656	24,843	25,137	25,431	25,726
IMPORTS	1,418	1,931	1,639	1,621	1,703	2,360	2,216	1,970	2,935	2,756	2,857	3,056	2,948	-542	-204	133	586	1,147	1,600	2,054	2,507

Source: own work.

Appendix 4: Inputs used for calculating cost prices of various power plants and energy sources.

POWER PLANT/ENERGY SOURCE	YEAR	INV. COST (EUR/kW)	EFFICIENCY (%)	AUTOCOM. (%)	FIXED O&M (% yr)	VAR. O&M (EUR/MWh)	FUEL PRICE (EUR/MWh)	CARBON PRICE (EUR/t)	CARBON INT. (tCO2/kWh therm)	NOMINAL WACC	CAP. FACTOR	LIFETIME (yr)	DECOM. (EUR/MWh)	COST PRICE (EUR/MWh)
TEŠ 5&6 (weighted)	2021													117
COAL CHP	2021	1,675	80%	3%	3%	4	9	54	0.387	6.69%	0.23	45	1	131
NATURAL GAS OCGT	2030	430	40%	3%	3%	3	31	100	0.2	2.73%	0.25	45	1	149
NATURAL GAS CHP	2021	1,675	80%	3%	3%	4	40	54	0.2	2.73%	0.41	45	1	103
	2030	1,675	80%	3%	3%	4	31	100	0.2	2.73%	0.41	45	1	103
HYDROGEN OCGT	2030	430	40%	3%	3%	3	97			2.73%	0.25	45	1	269
	2040	526	40%	3%	3%	3	89			2.40%	0.1	45	1	274
HYDROGEN CHP	2030	1,675	80%	3%	3%	4	97			2.73%	0.41	45	1	163
	2040	2,047	80%	3%	3%	4	89			2.40%	0.41	45	1	158
NATURAL GAS CCGT	2030	893	60%	3%	3%	4	31	100	0.2	2.73%	0.5	45	1	103
HYDROGEN CCGT	2030	893	60%	3%	3%	4	97			2.73%	0.5	45	1	187
	2040	1,092	60%	3%	3%	4	89			2.40%	0.3	45	1	186
HPP	2021													27
	2030													27
	2040													27
ČHE Avče	2021	659	74%	2%	1%		32			5.23%	0.15	80	1	77
	2030	659	74%	2%	1%		27			5.23%	0.15	80	1	70
	2040	659	74%	2%	1%		22			5.23%	0.15	80	1	63
PČHE Rudar	2040	1,700	74%	2%	1%		22			5.23%	0.15	80	1	114
NPPK1	2021													27
	2030													27
	2040													27
JEK2	2040	5,270	35%	5%	3%	5	5			5.00%	0.95	80	5	80
BATTERY STORAGE - in front of the meter	2021	1,150	90%	0%	1%		32			11.00%	0.1	20	1	211
	2030	905	90%	0%	1%		27			4.30%	0.1	20	1	117
	2040	599	90%	0%	1%		22			4.12%	0.1	20	1	82
BATTERY STORAGE - behind the meter	2021	1,994	90%	0%	1%		32			11.00%	0.1	20	1	329
	2030	1,569	90%	0%	1%		27			4.30%	0.1	20	1	174
	2040	1,038	90%	0%	1%		22			4.12%	0.1	20	1	118
SPP on TN (new)	2021	716	100%	0%	1%					3.50%	0.117	25	1	50
	2030	563	100%	0%	1%					2.96%	0.117	25	1	38
	2040	393	100%	0%	1%					2.81%	0.117	25	1	26
SPP on DN (new)	2021	1,148	100%	0%	1%					3.50%	0.117	25	1	80
	2030	916	100%	0%	1%					2.96%	0.117	25	1	61
	2040	825	100%	0%	1%					2.81%	0.117	25	1	54
WPP (new)	2021	990	100%	0%	3%					10.60%	0.19	25	1	87
	2030	968	100%	0%	3%					2.80%	0.19	25	1	51
	2040	941	100%	0%	3%					2.66%	0.19	25	1	49
OTHER	2021													75
	2030													75
	2040													75
ELECTROLYSER AT JEK2	2040	303	47,8 (kWh/kg-H2)	2%	2%	3	80			4.06%	0.95	20	1	4.2
WEIGHTED ELECTROLYSERS NON-JEK2	2030	348	50.225	2%	2%	3	48			4.30%	0.3	20	1	3.2
	2040	259	44.625	2%	2%	3	48			3.73%	0.45	20	1	2.6
IMPORTS	2021													90
	2030													84
	2040													80

Source: Pietzcker, Osorio & Rodrigues (2021), European Commission (2016b and 2020e), Polzin et al. (2021), Bachner, Mayer & Steining (2019), Mervar (2019a), ENTSO-E database and International Energy Agency (2020).

Appendix 5: Annual, average and total investments in broader electric power system (i.e. including the socio-economic restructuring plan of the SAŠA region, the funds covering TEŠ losses and total expenses for CHP plants) (EUR M).

TOTAL INVESTMENTS (EUR M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	TOTAL 2022-2040
TEŠ&PV RESTRUCTURING PLAN (state aid excl. EU and own funds)					258	258														517
of this investment plan					101	85														185
of this to cover losses					158	174														331
SAŠA REGION RESTRUCTURING PLAN AND CLOSURE OF COAL-RELATED OBJECTS (state and private own funds excl. EU funds)	104	104	104	104	104	104	104	104	104	16	16	16	16	16	16	16	16	16	16	1,100
SPP*	124	121	111	108	326	324	316	307	298	256	252	247	243	238	167	164	160	157	154	4,073
WPP		22	22	22	22	22	22	21	21	26	26	26	25	25						301
sHPP				4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	61
PČHE Rudar*						26	26	64	64	64	64									306
BIOGAS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	45
JEK2					513	613	788	813	788	563	563									4,638
CHP*		22	43	43	43	22	22	22	22	8	8	18	18	18	18	18	18	8	8	377
OCGT		11	11	11	11	11	11	11	11			5	5	5	5	5	5			120
CCGT*	0	25	25	25	25	25	25	0				9	9	9	9	9	9			209
BATTERY STORAGE*	24	31	26	163	81	82	79	77	74	72	69	67	64	62	10	9	9	9	8	1,015
DSM	10	10	10	10	10	10	10	10	0											80
ELECTROLYSER AT JEK2									22	22	22									67
ELECTROLYSERS				4	8	8	8	8	7	33	31	30	29	28	46	44	41	39	37	402
H2 STORAGE&TRANSMISSION													55	55	55	55	55	55		330
NETWORK INVESTMENTS	385	385	385	385	385	385	385	385	385	262	262	262	262	262	262	262	262	262	262	6,081
SUM - YEARLY	649	734	740	882	1,792	1,896	1,801	1,828	1,803	1,327	1,318	686	733	724	594	588	582	552	491	19,721
AVERAGE PER YEAR	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	1,038	
SUM - TOTAL	19,721																			

*excl. TEŠ&PV restructuring plan

Source: own work.

Appendix 6: Annual, average and total investments in narrower electric power system (i.e. excluding the socio-economic restructuring plan of the SAŠA region, the funds covering TEŠ losses and including half of the expenses for CHP plants) (EUR M.

INVESTMENTS IN ELECTRIC POWER SYSTEM	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	TOTAL 2022-2040
TEŠ&PV INVESTMENT PLAN	0	0	0	0	101	85	0	0	0	0	0	0	0	0	0	0	0	0	0	185
SPP*	124	121	111	108	326	324	316	307	298	256	252	247	243	238	167	164	160	157	154	4,073
WPP	0	22	22	22	22	22	22	21	21	26	26	26	25	25	0	0	0	0	0	301
sHPP	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	61
PČHE Rudar*	0	0	0	0	0	26	26	64	64	64	64	0	0	0	0	0	0	0	0	306
BIOGAS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	45
JEK2	0	0	0	0	513	613	788	813	788	563	563	0	0	0	0	0	0	0	0	4,638
CHP*	0	11	21	21	21	11	11	11	11	4	4	9	9	9	9	9	9	4	4	188
OCGT	0	11	11	11	11	11	11	11	11	0	0	5	5	5	5	5	5	0	0	120
CCGT*	0	25	25	25	25	25	25	0	0	0	0	9	9	9	9	9	9	0	0	209
BATTERY STORAGE*	24	31	26	163	81	82	79	77	74	72	69	67	64	62	10	9	9	9	8	1,015
DSM	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	80
ELECTROLYSER AT JEK2	0	0	0	0	0	0	0	0	22	22	22	0	0	0	0	0	0	0	0	67
ELECTROLYSERS	0	0	0	4	8	8	8	8	7	33	31	30	29	28	46	44	41	39	37	402
H2 STORAGE&TRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	55	55	55	55	55	55	0	330
NETWORK INVESTMENTS	385	385	385	385	385	385	385	385	385	262	262	262	262	262	262	262	262	262	262	6,081
SUM - YEARLY	545	618	615	756	1,509	1,607	1,686	1,712	1,688	1,307	1,299	661	708	699	569	563	557	532	471	18,102
AVERAGE PER YEAR	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	
SUM - TOTAL	18,102																			
*excl. TEŠ&PV restructuring plan																				

Source: own work.