

Pathways to Low Emission Energy Systems in the Baja California Peninsula

A Study of Implementation of Renewable Energy in Isolated Systems

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LUNDS
UNIVERSITET

Thesis for the degree of Master of Science

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ISRN LUTMDN/TMHP-25/5613-SE

ISSN 0282-1990

Abstract

As the global energy sector undergoes a necessary transition toward renewable sources, Mexico has committed to significantly expanding its clean energy capacity. The Baja California Peninsula, with its rich solar and wind resources, presents a unique opportunity to lead this shift. The peninsula is composed of two states: Baja California and Baja California Sur. Baja California operates one electrical system, while Baja California Sur has two distinct systems. These regions are isolated from the national grid, with the exception of Baja California's northern part, which is connected to the United States at two points in the north. However, the geographical isolation of the region from the national grid introduces both technical and economic challenges that must be addressed to enable a more efficient and integrated energy system.

This study explores potential energy transition pathways for the Baja California peninsula by modeling various scenarios. The analysis evaluates the feasibility and impact of integrating renewable energy sources, particularly solar and wind power, alongside energy storage solutions to ensure grid stability and meet future energy demands.

The results highlight that solar power, combined with energy storage, overall offers the most cost-effective pathway to meet the peninsula's growing energy demand, reducing reliance on fossil fuels. However, the findings also reveal key challenges that must be addressed to achieve a successful transition, including infrastructure bottlenecks, high initial capital costs, and the need for extensive policy support. Expanding and modernizing the transmission network is a critical factor in enabling renewable energy integration, as the most resource-rich regions for renewable energy are often located far from the existing grid.

The potential for overproducing electricity for storage and export appears promising in terms of reducing emissions and ensuring long-term cost-effectiveness. However, its feasibility is heavily reliant on the creation of favorable policy environments, which include clear incentives for renewable energy development and a stable regulatory framework for energy trade. This study highlights the critical need for strong policy leadership and substantial investments in both infrastructure and technology to enable a successful transition to a sustainable energy system.

In conclusion, while technical solutions for decarbonizing electricity production in the BC peninsula exist, achieving net-zero emissions will require coordinated efforts across multiple sectors. The success of this transition depends not only on technological advancements but also on political will, societal engagement, and international cooperation. Future research should explore the effectiveness of policy incentives, regulatory frameworks, and market mechanisms in accelerating renewable energy adoption, as well as the potential for cross-border energy trade or connecting the systems with each other or the national grid.

Acknowledgements

This thesis was made in collaboration with INECC in Mexico (El Instituto Nacional de Ecología y Cambio Climático), and their government collaboration with DEA (the Danish Energy Agency). The thesis was done at the department of Energy Sciences at Lund University.

We would like to thank all the people that have helped us along the way during this thesis. We want to thank Josue Alberto Valenzuela Ahumada, Secretaría de Economía e Innovacion in Baja California, for the help during our stay in Tijuana and with the comprehensive interview. Also, we want to thank Cristina Rubio Gonzales for facilitating contacts in La Paz and for letting us present our work at the climate forum at the Autonomous University of Baja California Sur (UABCS). We also want to thank Alfredo Sergio Bermúdez Contreras, Professor at UABCS, for the interesting interview. Additionally, we want to thank Roberto Ulises Ruiz Saucedo for helping us with the scope in the early works of the project and for the insightful meeting in Mexico City.

We would also really like to thank our supervisor at DEA/INECC, Kristian Voss Olesen, for the valuable inputs on the project during several months and the guidance and facilitation of contacts during our trip to Mexico. We also want to thank our other supervisor Martin Andersson for the guidance throughout the project.

Lastly, we want to thank Åforsk for granting us a scholarship, which enabled our very valuable trip to Mexico.

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List of Abbreviations

BC	Baja California
BCS	Baja California Sur
CENACE	El Centro Nacional de Control de Energía
CF	Capacity Factor
CFE	Comisión Federal de Electricidad
CHP	Combined Heat and Power
EV	Electric Vehicle
GHG	Green House Gas
GHI	Global Horizontal Irradiance
LEAP	Low Emission Analysis Platform
LIE	Ley de la Industria Eléctrica, Electricity Industry Law
NEMO	Next Energy Modeling system for Optimization
O&M	Operations and Maintenance
PHS	Pumped Hydro Storage
NREL	The National Renewable Energy Laboratory
PAMRNT	Programas de Ampliación y Modernización de la Red Nacional de Transmisión
RNT	Red Nacional de Transmisión
RGD	Red General de Distribucion
SEN	Sistema Eléctrico Nacional
SENER	Secretaría de Energía de México
SIBC	Sistema Interconectado Baja California
SIBCS	Sistema Interconectado Baja California Sur
SIM	Sistema Interconectado Mulegé
SIN	Sistema Interconectado Nacional
SLCP	Short-Lived Climate Pollutants
V2G	Vehicle-to-Grid
WECC	Western Electricity Coordinating Council

1 Introduction

Climate change is a pressing global issue, impacting weather patterns, ecosystems and communities worldwide. As awareness of these challenges grows, so does the need for effective solutions. This creates an opportunity for regions to adopt sustainable practices that promote the environment while addressing the demands of a changing world.

In 2023, the power industry was the largest polluting sector, responsible for over 38% of global emissions (Statista 2024a). With global energy demand increasing, the adoption of clean energy solutions is crucial to reducing emissions. To meet the Paris Agreement's 2°C target, and ideally stay within the 1.5°C threshold, the world must triple its installed renewable energy capacity by 2030 compared to 2024 levels (IRENA 2024a).

During COP27 in Egypt in 2022, Mexico emerged as one of the countries with ambitious renewable energy goals, committing to double its renewable energy capacity by 2030. Achieving this goal requires a significant acceleration in the implementation of renewable energy technologies (Fernandez 2023).

Mexico, a nation rich in cultural diversity and natural resources, faces both challenges and opportunities in addressing climate change. The country is particularly vulnerable to global warming, experiencing extreme weather events, shifting precipitation patterns and rising temperatures. Currently, nearly 80% of Mexico's electricity production relies on fossil fuels, yet the country holds substantial potential for renewable energy development. One region that can lead this transition is the Baja California peninsula in northwestern Mexico. Comprising two states, Baja California and Baja California Sur, the peninsula boasts diverse ecosystems and abundant natural resources, presenting a unique opportunity to adopt sustainable energy solutions. However, the electrical grids of these states are disconnected from the national grid, which presents both challenges and opportunities (Institute of the Americas n.d.). With population growth and expanding economic activities driving energy demand, the region faces an urgent need for cleaner and more efficient energy sources.

By using renewable energy technologies such as solar and wind, Baja California and Baja California Sur can meet their growing energy needs while promoting economic growth and environmental control. Supportive policies will be critical to enabling a sustainable energy future that aligns with Mexico's national climate goals. For the peninsula, pursuing this goal represents an opportunity to become a leader in sustainable development and actively contribute to the global fight against climate change.

This report will explore the pathways and strategies for the Baja California peninsula to achieve low to zero emissions in its electricity generation. By analyzing current energy practices and identifying potential renewable energy sources, the aim is to provide a clear road map for a sustainable future that benefits both the region and the planet.

1.1 Aim and Scope

The primary aim of the study is to explore and evaluate various pathways for integrating renewable energy and energy storage into the electricity grids of the Baja California Peninsula. By assessing the feasibility and impact of different scenarios, the study will provide critical insights into how the peninsula can transition to a sustainable and clean energy future while meeting growing demand and ensuring reliability of the grid. Furthermore, the questions that the report will answer are the following:

- What are the different pathways for the electrical system in the Baja California Peninsula in terms of:
 - Amount of emissions
 - Cost of production
 - Speed in which it can be implemented
- How feasible are the different pathways in regard to resources and policy frameworks?
- What are the current and future biggest challenges in the electrical system of the Baja California Peninsula?

1.2 Delimitations

This study focuses on evaluating the impacts of different energy scenarios within the Baja California Peninsula.

Geographically, the study includes the entire Baja California Peninsula, but does not treat it as a single unified entity. Instead, the three distinct regions **Baja California**, **Baja California Sur** and **Mulegé** (a region in Baja California Sur) are evaluated. This approach allows for a detailed evaluation of their unique and common challenges, providing the basis for a discussion on regional synergies and strategies to address individual and collective issues in the future.

Furthermore, the analysis does not account for potential disruptions caused by extreme weather events, geopolitical risks, or other unexpected events. Although these factors could significantly affect energy security and system reliability, they are outside the scope of this study to maintain a controlled focus on the defined scenarios.

Typically, in a life cycle perspective, emissions from solar and wind energy are considered low, primarily accounting for the construction of power plants (Vattenfall, 2023). However, in this study, emissions from solar and wind are assumed to be zero to simplify and streamline the study's scope.

The analysis excludes the potential impacts of electric vehicle (EV) adoption on electricity demand. This assumption was made due to the high uncertainty surrounding the pace of EV development and deployment in the region. Factors such as the availability of charging infrastructure, government incentives, consumer adoption rates, and advancements in EV technology introduce significant variability, making reliable projections challenging within the scope of this study. By excluding this factor, the study focuses on a more stable and predictable baseline for electricity demand, allowing for a clearer analysis of the core scenarios. However, it is important to note that widespread EV adoption could lead to significant increases in electricity consumption, potentially altering the outcomes of the energy scenarios. It is worth considering that a system without EV adoption might appear more stable and predictable, but the integration of Vehicle-to-Grid (V2G) technology could mitigate some of these challenges, potentially stabilizing demand even with high EV penetration.

1.3 Disposition

Section 1 outlines the research objectives, scope, and study limitations, providing a foundation for the analysis. This is followed by Section 2, which presents essential background information to contextualize the study.

The methodology used in this research is detailed in Section 3, covering data collection methods, key assumptions, and the approach to scenario modeling. This section also introduces the primary analytical tools and discusses the design of the chosen scenarios.

Section 4 provides essential background information on the Mexican electrical system, focusing on the Baja California Peninsula. It includes an overview of regional energy networks, electricity demand trends, and current production capacities.

The results are presented in Section 5, beginning with the Baja California system in isolation and moving on to an analysis of anticipated challenges in regional energy infrastructure.

The discussion of results, feasibility, challenges in infrastructure and policy, and uncertainties are presented in Section 6 and the conclusions are given in Section 7.

Finally, Section 8 proposes areas for future research.

2 Background

2.1 The Electrical System of Mexico

Mexico's electrical system is one of the largest in Latin America and plays a critical role in the country's economic and industrial development. It comprises a complex infrastructure responsible for generating, transmitting and distributing electricity nationwide. The National Electric System (SEN) is divided into several regions interconnected through a network of high-voltage transmission lines (SENER n.dA).

Mexico's electrical infrastructure consists of two major components: the Red Nacional de Transmisión (RNT) and the Red General de Distribución (RGD). The RNT is responsible for transmitting electricity over long distances at high voltage levels, while the RGD distributes electricity to end users on regional and local scales. These networks cover most of the country, although certain regions, like Baja California (BC) and Baja California Sur (BCS), remain isolated from the national grid. (SENER n.d.A)



Figure 1: A map of Mexico divided into the different regional energy systems where the areas marked with 7, 7* and 7** mark the three systems in the Baja California Peninsula. Retrieved from CENACE 2024

Historically, Mexico's electrical system has been dominated by the state-owned Comisión Federal de Electricidad (CFE). The energy reform of 2013 marked a turning point, allowing private companies to enter the electricity market, particularly in generation and distribution. This reform aimed to modernize the grid, boost competition, and attract investment in renewable energy (De Imus, P., 2015). In recent years, however, a significant policy shift has emerged, prioritizing CFE in the dispatch of electricity. This change represents a marked departure from the competitive framework introduced by the reform. Under this new paradigm, CFE's role as the primary operator in the sector has been strengthened, often at the expense of private investment and the integration of renewable energy sources into the grid. This policy realignment has now been officially codified, signaling a definitive move away from the principles of market liberalization (GeoComunes 2024). Additionally, a draft bill reinforces this by mandating that CFE supply at least 54% of the national grid's electricity (Martinez, A. 2025).

The main responsible for the national electric system is SENER (Ministry of Energy, Secretaría de Energía). According to the Electrical Industry Law (Article 6, Section I) SENER must ensure the efficiency, quality, reliability, continuity and security of the national system. Further, Article 109 states that CENACE (National Center for Energy Control) will prioritize its operations to guarantee that the SEN functions efficiently and sustainably. To achieve this, CENACE forecasts demand and consumption which are essential to ensure a reliable electrical supply. Supporting the productive activities of various sectors of the economy are crucial for promoting national economic development and the well-being of the Mexican people (CENACE 2024).

In 2024, Mexico has set a clean energy goal of achieving at least 45% of its electricity generation from clean energy sources by 2030. These sources are defined as renewable energy, nuclear power, and combined heat and power (CHP) systems that emit less than 100 kg of CO₂ per MWh. As of 2023, clean energy generation accounted for only 23.19% of the total electricity production, falling significantly short of the target. However, regarding installed capacity, clean energy sources now represent over 36% of the total capacity (SENER n.d.A).

2.2 Baja California Peninsula

Baja California, translating to Lower California in English, is a Mexican peninsula located in the northwest of Mexico, bordering the US states California and Arizona to the north and the Mexican state Sonora to the east. The peninsula consists of two Mexican states, BC in the northern half and BCS in the southern part. It's approximately 1 220 km long and 40 to 240 km wide, with an area of around 143 396 square km (Encyclopædia Britannica, n.d.A).

2.3 Electrical Systems in Baja California and Baja California Sur

The Baja California peninsula is unique in Mexico due to its complete disconnection from the national grid, the Sistema Interconectado Nacional (SIN). The peninsula instead relies on three distinct electricity systems, each shaped by the region's geographical and infrastructural constraints. BC consists of one: Sistema Interconectado Baja California (SIBC). BCS consists of two electrical systems: Sistema Interconectado Baja California Sur (SIBCS) and Sistema Interconectado Mulegé (SIM) where the latter is located in the northern part of BCS. These systems serve different areas with varying population densities, energy demands, and capacities, highlighting the logistical challenges of maintaining reliable power in a region disconnected from the national grid.

SIBC consists of the whole state of BC and an area in the neighboring state of Sonora called San Luis Rio Colorado, which currently does not have domestic power production. Therefore, to meet the electricity demand, the importation of electrical energy from the Mexicali area in Baja California is required (CENACE, n.d.).

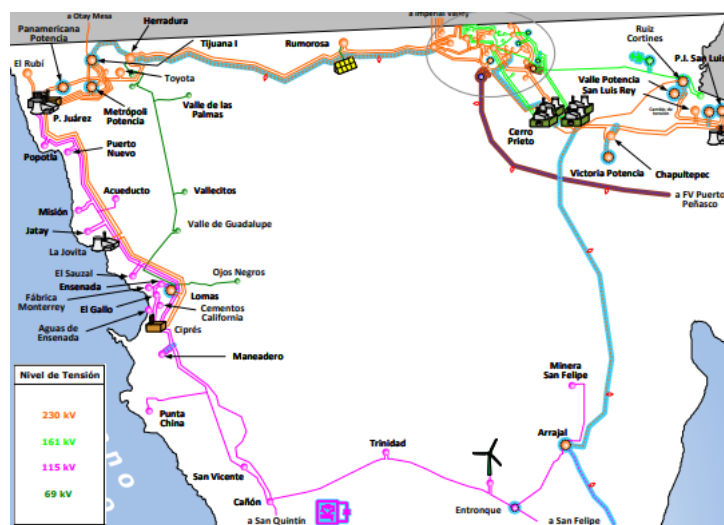


Figure 2: Map showing the system in Baja California. Altered image retrieved from CENACE 2024

The system provides 3.9 million people with electricity where the average use is 4 150 kWh per capita, which is 54.6% higher than the national average (SENER n.d.). The capital of BC, Mexicali, lies on the U.S border and has a population of about one million people. Other major cities are Tijuana and Ensenada. Until the mid-1970s several areas of the state were isolated but since then an expansion of highways has been made, making it a more accessible state (Encyclopædia Britannica, n.d.B). A plan to connect the SIBC system to the national grid was made in 2016 but has been canceled since (CENACE, n.d.).

SIBCS and SIM are both geographically in the state of BCS as mentioned, but are two different electrical systems. SIBCS includes the main cities in the state of BCS: Comandú, Loreto, Los Cabos and the capital La Paz, shown in the figure below. SIM is isolated from both the SIBC and SIBCS as well as the national system. Geographically, it is made up of the municipality of Mulegé, which is the largest municipality in BCS, where the main cities are Santa Rosalía (14 000 inhabitants) and Guerrero Negro (13 500 inhabitants)(SENER n.d.).

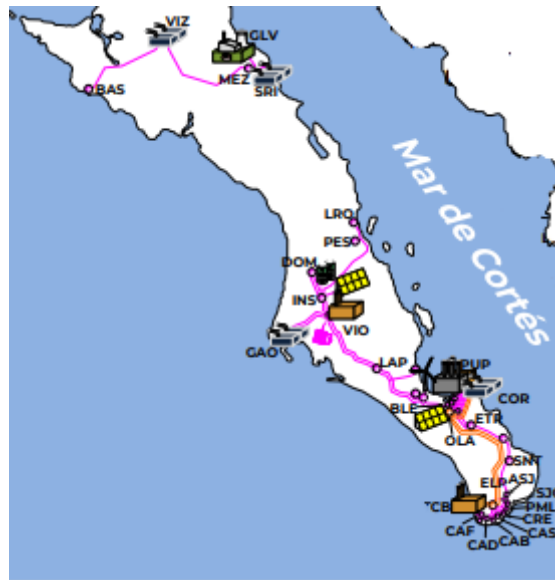


Figure 3: Map showing the two systems in the state of Baja California Sur. SIM in the northern part and SIBCS in the southern part of the peninsula. Altered image retrieved from CENACE 2024

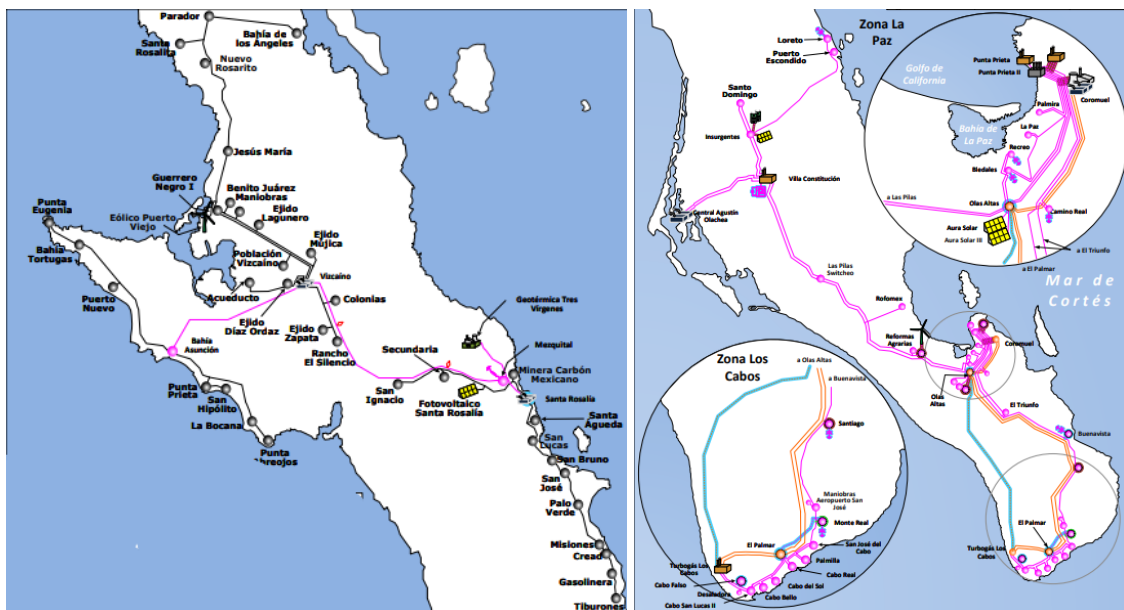


Figure 4: Detailed overview of the different systems. The black lines have a voltage of 34.5 kV, the pink 115 kV and the orange 230 kV. The blue line is a pipeline for fossil fuels. Altered image retrieved from CENACE 2024

The two systems in total provide around 0.8 million people with electricity, and the average annual use is around 4 180 kWh per capita, which is 56.0% higher than the national average. 94.5% of the population and demand are covered by the SIBCS while SIM covers the rest. The areas in BCS that had the greatest growth were Loreto (SIBCS) with 8.3% and Santa Rosalía (SIM) with 2.7% (SENER n.d.).

3 Method

This section outlines the methodology used in the study. It begins by introducing the scenario modeling, which is structured around four key steps: scenario definition, data gathering, modeling and evaluation.

The semi-structured interviews aimed to provide background information about the current state of the electricity system of the Baja California peninsula and the feasibility of the implementations. In addition, it was also used to get inputs on the scenario modeling.

3.1 Software tools

To answer the research questions, LEAP (Low Emissions Analysis Platform) and NEMO (Next Energy Modeling System for Optimization) were utilized, both developed by the Stockholm Environment Institute. LEAP is a widely used tool for energy system analysis, focusing on emissions and sustainability, while NEMO is designed for optimizing energy system planning. These tools were chosen for their ability to model complex energy systems and assess environmental and economic impacts.

LEAP was used as a scenario-based modeling tool where data is structured within a demand-supply framework. Input parameters included energy demand across different sectors, fuel types, technology efficiencies, and policy constraints. Based on these inputs, LEAP calculates the energy balance by tracking energy flows from extraction and production to final consumption. It also estimates emissions by applying emission factors to different fuels and processes, while also including cost assessments related to energy production, infrastructure investments, and operational expenses. LEAP does not optimize the system but enables comparative scenario analysis, making it possible to evaluate different policy interventions, technological developments, and economic conditions.

To complement LEAP, NEMO was used for optimization-based energy system planning. This tool applies mathematical programming to determine the most cost-efficient mix of energy technologies that can meet projected demand while considering system constraints. Input data included power plant characteristics, operational and capital costs, fuel prices, renewable energy availability, and policy targets. NEMO optimizes investment and dispatch decisions by identifying which power generation technologies should be expanded, retired, or introduced within a given planning horizon. It also ensures that energy supply meets demand in a cost-effective way while complying with environmental and policy constraints.

In this study, LEAP and NEMO were integrated to combine scenario analysis with optimization. LEAP was used to establish baseline energy demand projections and emissions scenarios, while NEMO refined these by optimizing the system configuration under different constraints. This approach provided a structured and transparent way to assess possible future energy pathways, considering both technological and economic aspects to gain a better understanding of the implications of different energy transition strategies.

3.2 Scenarios

The selected scenarios for this study were designed to explore pathways for meeting electricity demand in the Baja California peninsula while prioritizing the expansion of renewable energy to reach low or zero emissions in the electricity production. The four scenarios chosen are as follows:

- 1 - **Baseline** (BAS). Assumes the current plans for future capacity investments
- 2 - **Continued use of Fossil Fuels** (FOS). Cover the electricity demand with continued use of fossil-based electricity production but with a higher share of renewable energy, letting LEAP determine the most cost efficient scenario without renewable limitations.
- 3 - **Renewables with Storage** (REN). Cover the electricity demand with 100% renewable energy combined with energy storage
- 4 - **Export and Storage** (EXP). Reach 100% renewable energy 2037 and cover costs with electricity and hydrogen export

These scenarios were selected based on several key criteria. The first scenario, the *Baseline*, serves as a reference point to compare the effectiveness of different mitigation strategies, particularly regarding cost and emissions. This allows for a clearer understanding of the potential benefits and trade-offs of pursuing renewable energy expansion. The planned capacities expansions are showed in Appendix A.

In the second scenario, *Continued use of Fossil Fuels*, fossil fuels continue to play a key role in meeting electricity demand. This scenario tests whether fossil fuels are still necessary as a backup or if they can eventually be phased out. By maintaining a higher share of renewable energy while relying on fossil fuels for stability, this scenario explores the balance between transition fuels and renewable energy integration.

The third scenario, *Renewables with Storage*, envisions a fully renewable energy system where storage technologies replace the need for fossil fuels, providing stability during periods when renewable generation is low. This scenario challenges the assumption that fossil fuels are required for grid stability, testing whether energy storage can fully support a renewable-based electricity grid.

The fourth scenario, *Export and Storage*, takes a more forward-looking approach by considering the Baja California peninsula’s potential as an energy exporter. This scenario aims to meet regional energy demands through 100% renewable energy, while also generating surplus electricity for export. By integrating energy storage, this scenario ensures that excess renewable energy can be stored and managed, creating opportunities for economic growth through energy exports. This scenario explores both the potential for regional energy independence and the economic benefits of cross-border energy trade.

3.3 Modeling the scenarios

The process of modeling in LEAP followed a structured and systematic approach, focusing on how constraints were selected and how the system was progressively built. The method used to create the different scenarios is outlined in Figure 5, illustrating the flow from assessing the situation to developing various mitigation strategies.

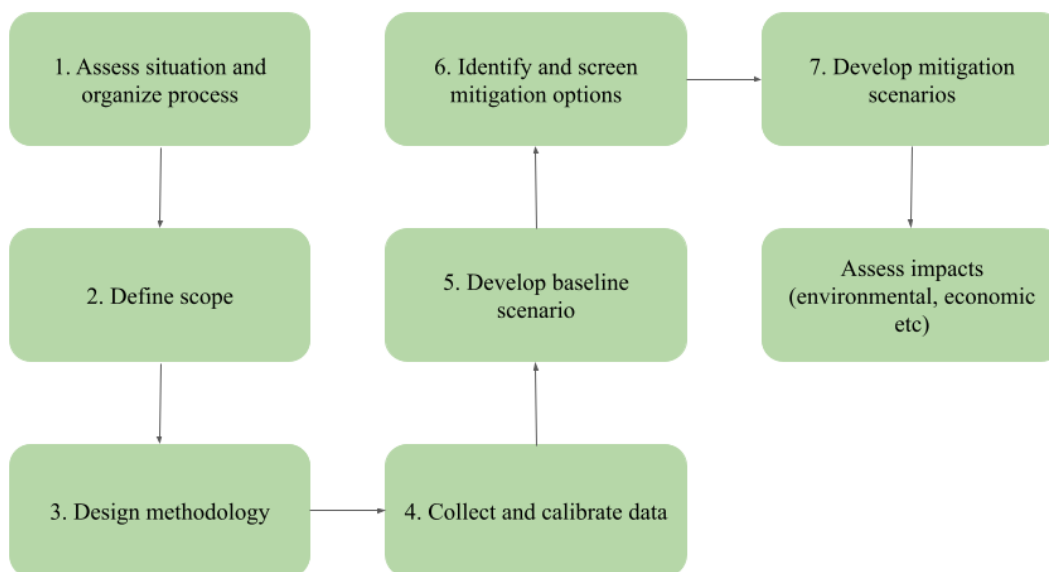


Figure 5: Strategy for scenario modeling

First, a thorough assessment of the region’s energy and environmental needs took place. This stage was essential for understanding the challenges at hand, such as energy shortages, the region’s dependence on fossil fuels and emission-related issues. The scope of the study was then clearly defined. The boundaries of the study were set to capture significant data while remaining manageable for practical analysis.

Once the scope was established, the methodology was designed to guide the rest of the project. This phase involved selecting the most appropriate tools, in this study thus LEAP and NEMO, to model the system effectively. It also required identifying critical variables, like energy demand, resource availability, and emissions, that would influence the scenarios. With the methodology in place, data collection became a crucial step.

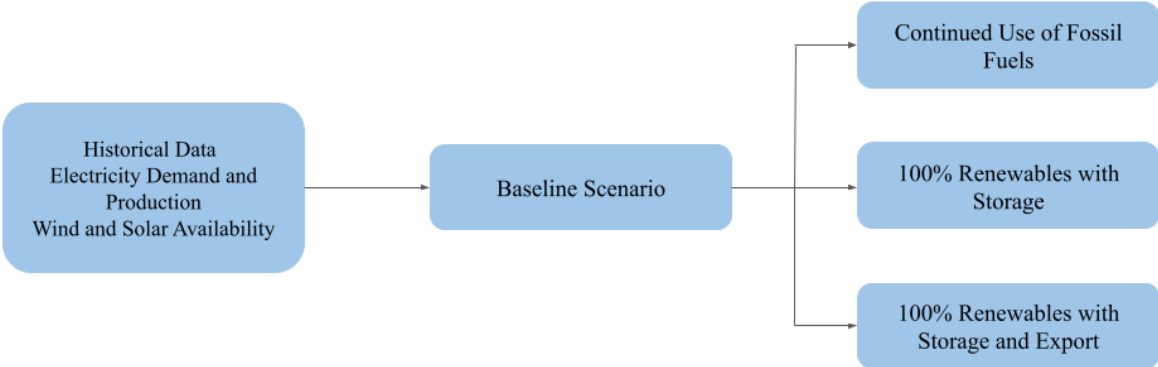


Figure 6: Data structure and scenario inheritance

In this process, the baseline scenario was used as a starting point to analyze the effects of various interventions. Figure 6, visually represents the structure of the data and how the different scenarios build upon the baseline. The baseline scenario is rooted in historical data, capturing current energy consumption, production, and emissions levels. Furthermore, the planned expansion of the installed capacity was added, which was retrieved from the government report *Programas de Ampliación y Modernización de la Red Nacional de Transmisión y de los elementos de las Redes Generales de Distribución que correspondan al Mercado Eléctrico Mayorista (PAMRNT 2024-2038)* in the figures 4.9.3 and 4.9.6.

In the FOS scenario, there were no limitations to what type of electricity generation was to be expanded. Rather, to find out the most cost effective pathway for the electricity production, LEAP optimized based on only cost of production. However, the expansion of installed capacities was limited to realistic annual increments to reflect plausible growth rates. In this scenario, storage expansion was set to zero across all regions, and geothermal energy in the SIBC region was held constant.

In the REN scenario, the LEAP model was configured to achieve a renewable energy share of 100% by 2040. This target aligns with the goal of achieving zero emissions. To guide the transition, constraints were applied to the annual addition of wind, solar, and battery capacities, mirroring the approach used in the first scenario. Geothermal energy in the SIBC region was also set to remain constant in this scenario.

The EXP scenario builds upon the previous scenario by utilizing the amount of curtailed energy to determine the optimal size of hydrogen production facilities for each system, built in the year 2035. In BC, the plant has a capacity of 100 MW, while in BCS and Mulegé, the capacities are 20 MW and 1 MW, respectively. The cost and production data are derived from *Lazard's Levelized Cost of Hydrogen Analysis—Version 2.0*. A PEM electrolyzer was chosen for this scenario due to its suitability for less consistent energy supplies, such as the curtailed energy in this context.

In the EXP scenario, any excess curtailed energy remaining after hydrogen production is assumed to be exported to the U.S. This calculation is performed in Excel, with the assumption that the exported energy can be sold at a profit based on California's electricity price.

In LEAP, the electricity generation during a year can be expressed in a load shape, which in turn is divided in selected *time-slices* during the year. This is used to get detailed data from generation and demand and check if they can be met at all times. Ideally, the time slices would be *every hour during the year*, resulting in 8760 time-slices, but this is very data intensive. To combine having details in the energy generation load shape and to reduce the computation time, **weekly and day/night**, which resulted in 104 time slices, was chosen. That provides insights in both daily and seasonal variations, which are important in weather-dependent electricity sources such as wind and solar. The demand load shape is shown in Section 4.

3.4 Data gathering

The majority of the required data was sourced from government reports by SENER (Secretaría de Energía de México) and CENACE, as well as from INECC. This included information on net energy consumption, the composition of energy systems, and historical data on production and costs, such as capital costs, fixed and variable O&M costs, and fuel costs. These data points were integral to the scenario modeling.

The analysis also incorporated projections of planned capacity additions, as outlined by CENACE in PAMRNT 2024–2038 (see Appendix A). These projections served as the foundation for modeling capacity changes across energy types and regions. Regional variations in energy capacity and the distribution of energy sources were accounted for to ensure that the scenarios reflected realistic conditions.

While the core data centered on planned expansions, adjustments were made to align with the study’s assumptions and scenario designs. This involved setting constraints on capacity growth and excluding certain energy types from expansion in specific scenarios. Details on these adjustments, including the capacity addition table and other modeling data, can be found in Appendix A.

3.5 Assumptions

Several assumptions were made in this study to streamline the analysis and focus on key outcomes.

For all power generation technologies, a salvage value of zero was assumed at the end of their operational life. This assumption is based on the difficulty of predicting the future value of materials and components, as well as the expectation that decommissioning, dismantling, and environmental restoration costs will outweigh any salvageable value. While this may underestimate the potential for certain technologies, such as solar and wind, where materials may retain value, it ensures a conservative estimation of life-cycle costs. Furthermore, decommissioning costs were assumed to be zero since their inclusion was deemed to have negligible impact on the final results and would not justify the additional effort required to obtain accurate figures.

In scenarios where fossil fuel-based energy sources are phased out, the maximum capacity and maximum annual capacity additions for these sources were set to zero to reflect a decision against further expansion. Conversely, for energy resources with planned expansions, capacity additions were constrained to projected levels. Realistic annual limits were also applied to solar, wind, and battery capacity additions across all scenarios. For geothermal energy in the SIBC region, it was assumed that the installed capacity remains constant throughout the studied period.

Furthermore, all energy sources currently powered by fossil fuels are assumed to continue using the same type of fuel as in the existing systems. Therefore, biofuels are not considered. Also, in accordance with Mexican terminology, gas turbines are referred to as 'turbo gas' in this report.

The demand curve in SIM was not available, so the assumption was made that Mulegé's demand curve mirrors that of BCS. This assumption is based on the similarity in geography and demographics between the two areas, and total energy consumption in Mulegé is estimated according to its population size relative to BCS.

Additionally, the age of all plants or when they are expected to decommission in the regions was not available. Hence, the expected lifetime of all plants was assumed to begin at the beginning of the historical data, which is the default in LEAP.

The analysis does not include new grid connections for energy import or export to and from the peninsula. As a result, the modeling focuses solely on locally available energy resources and infrastructure, without accounting for the potential benefits or challenges of increased regional or international energy integration. However, the implications of new grid connections are briefly discussed.

Furthermore, Carbon offsetting or carbon capture and storage (CCS) are excluded from the scope of this study as these approaches typically involve indirect strategies, such as the capture of carbon through natural processes, which do not directly address the issues of electricity generation and demand. Furthermore, these strategies are often viewed as longer-term mitigation measures and may not be relevant to the near-term energy scenarios under consideration. As a result, these factors are not incorporated into the study.

3.6 Interviews

To gain a deeper understanding of the changes occurring within the states, this study uses semi-structured interviews. The semi-structured format is particularly well-suited to the research objectives as it offers a balance between structure and flexibility. Predefined questions ensure that all critical topics are addressed systematically, while the open-ended nature of the format allows interviewees to elaborate on their perspectives, share unexpected insights and provide detailed experiences that might not surface in a more rigidly structured setting.

This choice serves several purposes. First, it facilitates the gathering of qualitative data, which is crucial for exploring complex topics in depth. Second, it encourages a conversational environment, enabling the identification of nuances in the information provided. Lastly, the interviews complement the literature review findings by validating and expanding upon existing knowledge with real world, context specific insights from the participants.

The aim of the interviews is to gather practical, detailed perspectives on the changes occurring within the states, especially on issues that might not be fully addressed in the literature or quantitative data. These insights are key to answering the research questions effectively and ensuring that the model's results are grounded in reality.

The selection of interviewees and organizations was guided by several key criteria. First, individuals with expertise in the energy systems of the two specific states were sought to provide detailed and state-specific insights. Second, someone with a broader understanding of the entire Mexican energy system was included to offer a wider perspective and discuss the feasibility of the study from a governmental standpoint.

By combining interview findings with literature and supplementary data, the study takes a comprehensive approach to understanding the issue. This combination of methods enhances the reliability, validity, and relevance of the results. The full set of interview questions is provided in Appendix B.

Additionally, the interviews were carried out without the support of recording devices or transcription, potentially resulting in human errors and inconsistencies within the data.

3.7 Indicators

The chosen indicators that were used to analyze the results of the models are presented below:

- **Energy production per year** - Represents the total electricity generated by each technology annually, measured in GWh, across the modeling period. This indicator was chosen to evaluate the overall capacity of each technology to meet demand over time.

- **Total installed capacity** - Represents the total installed generation capacity of each technology, measured in MW, across the modeling period. This indicator was included to assess the scaling potential of each energy technology and its ability to meet growing demand over time.
- **Time-sliced energy production** - Displays the distribution of electricity generation in MWh throughout the year, broken down into specific time slices. This provides insight into the variability and availability of energy generation at different times of the year, crucial for grid stability.
- **Emissions per year** - Indicates the yearly carbon dioxide emissions associated with energy production over the modeling period. This was selected to assess the environmental impact of each technology, particularly in terms of contributing to climate goals.
- **Cost of production per year** - Reflects the annual production cost for each technology across the modeling period. This was chosen to evaluate the economic feasibility and competitiveness of each energy technology in the long term.

3.8 Sensitivity Analysis

To assess the sensitivity of the models and understand the impact of key uncertainties, a sensitivity analysis was conducted. This analysis focused on the effect of varying two crucial parameters: **electricity demand growth**, **the social cost of carbon (SCC)** and **adding seasonal storage**. These parameters were selected due to their significant influence on both the energy demand projections and the environmental and economic outcomes in the models.

For the SCC, three values were tested: 0 USD per ton CO₂, 50 USD per ton (the baseline), and 185 USD per ton. This range allows for an evaluation of how different carbon pricing assumptions might influence model outcomes, particularly in terms of renewable energy adoption and the competitiveness of low-carbon technologies.

Additionally, a 2.5% demand growth rate, sourced from PRODESEN 2024-2038, was used to assess the impact of varying future demand projections on the system. This assumption is relevant for understanding how growth in energy demand could affect system design and performance.

To address the limitations of short-duration storage, 4-hour batteries were considered as the primary storage solution, with an additional analysis incorporating pumped hydro storage (PHS) as a complementary longer-duration storage option. PHS provides the capacity to store energy over extended periods, ensuring grid reliability during periods of low renewable generation.

The results were used to identify the most sensitive parameters and analyze their impact on total system costs and emissions. This methodology allowed us to highlight key uncertainties in system planning and how different technological and economic assumptions influence long-term decisions.

4 Data and Input Parameters

4.1 Electricity Demand

The yearly electricity demand during 2023 on an hourly basis in the different systems is presented in the three figures below, and as can be seen in all of them, the demand increased between the months of May and October compared to the rest of the year, which will be discussed further below. In SIBC, the peak demand occurred during 26th July at 3 457 MWh/h, in SIBCS the 3rd of August at 675 MWh/h and in SIM the 26th of September at 32.5 MWh/h.

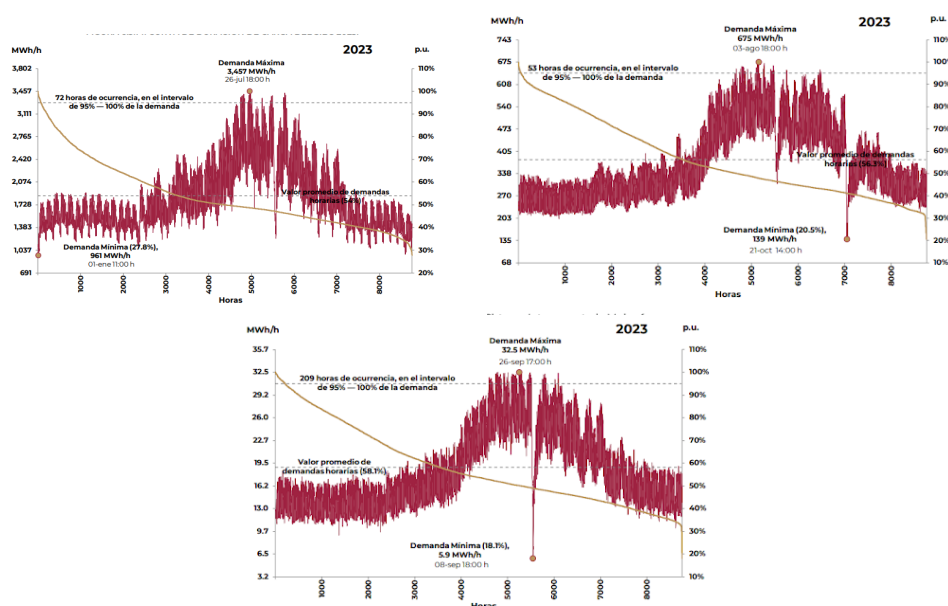


Figure 7: The hourly change in demand based on peak demand of the different systems during 2023. SIBC (first), SIBCS (second), SIM (third). Retrieved from CENACE 2024

The total gross demand for 2023 in SIBC was 16.3 TWh, which is a decrease of 2.1% compared to 2022. However, the peak demand during an hour increased by 2.9% compared to the previous year (CENACE, n.d.). In SIBCS the total gross demand during 2023 was 3.3 TWh, representing an increase of 8.0% compared to 2022, and the peak demand during an hour increased by 13.3% compared to the previous year. The main reason for this large increase is due to the flow of international and national tourists, one of the economic sectors that drives the consumption of the electrical system (CENACE, n.d.). The SIM is significantly smaller than the two other systems and the total gross demands during 2023 was 0.17 TWh, which is an increase of 0.7% compared to 2022 and the peak demand during a day increased by 1.4% compared to the previous year. (CENACE, n.d.).

The electricity demand changes not only depending on the season but also during the day. The figure below illustrates the hourly variations in electricity demand throughout the day in the different systems, displaying both summer and winter usage in separate graphs. In all three systems there is an increase in the demand as the day progresses, particularly in summer, when increased air conditioning is needed due to the hotter weather (CENACE, n.d).

In SIBC, summer demand is driven by increased air conditioning usage due to higher solar intensity, resulting in a peak difference of 1.6 GW, which is more than double the winter demand. In SIM, the disparity between summer and winter demand is even greater than in SIBC, where summer demand exceeds winter demand by over twice the amount, with an additional 19 MW recorded (CENAE, n.d.).

In SIBCS, the pattern is consistent, with summer demand more than double the winter demand, though the daily variation is smaller compared to SIBC. The largest seasonal difference in SIBCS is 349 MW. Overall, across all regions, summer demand significantly surpasses winter demand, primarily due to the increased need for cooling during the hotter months (CENACE, n.d.).

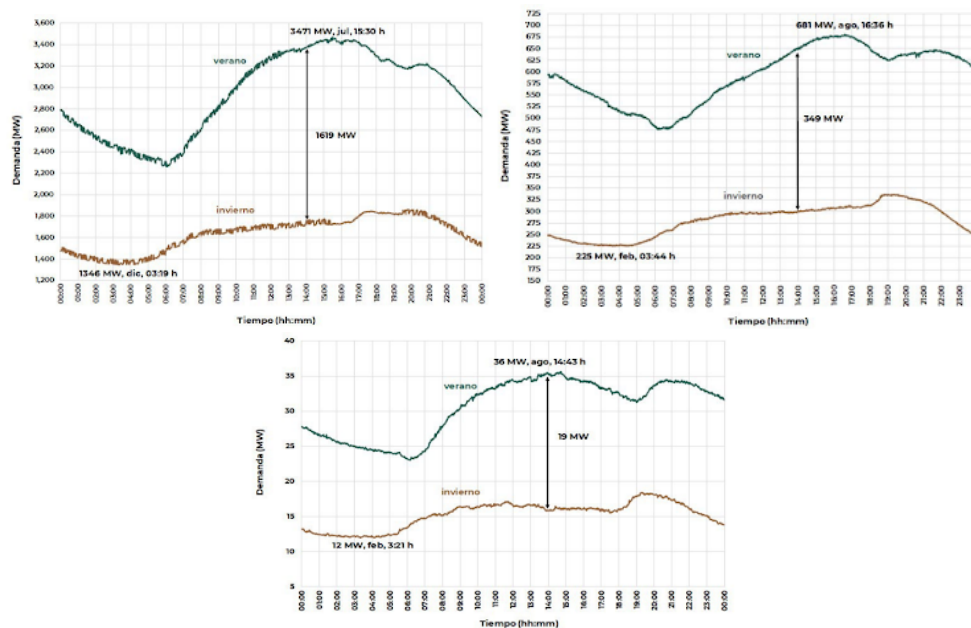


Figure 8: The difference between the daily hourly usage during summer and during winter. SIBC (first), SIBCS (second), SIM (third). Retrieved from CENACE 2024

In the SIBC system, Mexicali accounts for the highest electricity demand, comprising approximately 48.7% of the total, followed by Tijuana at 31.4%. Notably, Mexicali also saw the largest year-over-year increase in demand in 2023 compared to 2022, at 5.6%, with Ensenada following at 2.5% (SENER, n.d.B).

Interestingly, Mexicali, with a population of around one million, half that of Tijuana's two million, consumes significantly more electricity annually. Its total usage is 7.6 TWh compared to Tijuana's 5.2 TWh, translating to per capita consumption of 7.3 GWh and 2.7 GWh, respectively (Comisión Estatal de Energía de Baja California, n.d.A). This disparity is largely due to Mexicali's inland location and hotter climate. Surrounded by deserts, Mexicali experiences very warm and dry conditions, with summer temperatures averaging up to 45°C. Additionally, winters can be quite cold, necessitating heating. These extreme seasonal temperature variations drive high energy demand for climate control throughout the year (Comisión Estatal de Energía de Baja California, n.d.A)(Institute of the Americas, n.d.A).

Both Mexicali and Tijuana host large manufacturing sectors, with Mexicali also serving as a hub for agriculture. This combination can lead to competing interests during electricity supply shortages, particularly over rising prices, which pose challenges for the state's manufacturing sector. The industrial sector in BC is the primary electricity consumer, accounting for approximately 56.3% of usage, followed by residential consumption at 34.3% (Institute of the Americas, n.d.). Within the SIBC system, the industries with the highest electricity demands include steel, glass, water pumping, aerospace, aluminum wheel manufacturing, automotive, cement, and mining. These industries are concentrated primarily in Mexicali, Tijuana, and Ensenada (SENER, n.d.).

In BCS, key industries include cotton by-products, processed fish, and a significant fishing and aquaculture sector, producing mussels, lobsters, tuna, oysters, and clams. Cattle raising and subsistence agriculture dominate the rural areas, with wheat, beans, and cotton as the main crops (Encyclopædia Britannica, n.d.C). However, the mining industry and airport operations stand out as the most energy-intensive sectors in the region(SENER, n.d.).

In each of the systems, the energy demand is deemed to grow due to increase of population and industries. According to PRODESEN 2024-2038, the gross demand is estimated to have a yearly growth rate in the different systems according to the table below:

Table 1: Annual growth of gross demand 2023-2038 for the different systems. Data from PRODESEN 2024-2038

	SIBC	SIBCS	SIM
Annual Growth Rate (%)	3.3	3.5	2.1

4.2 Electricity Production SIBC

In the BC system, most electricity production is concentrated in the northern region near the cities of Mexicali, Tijuana, and Ensenada, all located in the northern part of the state. The system has a total installed capacity of 3.3 GW, with the primary production source being combined-cycle plants, followed by geothermal and turbo gas plants (SENER, n.d.B). In this report, gas turbines are referred to as Turbo gas in the rest of the report. Turbo gas, internal combustion, combined cycle, and conventional thermal power plants are all types of thermoelectric plants that rely on the combustion of fossil fuels. These power plants typically use natural gas, diesel, or oil. For detailed explanations, see *Supplementary Technology Theory* in Appendix A.

The majority of thermoelectric generation relies on the combustion of natural gas in SIBC. However, BC lacks indigenous natural gas production, leading to a heavy dependence on imports from the United States via cross-border pipelines to meet its electricity generation needs (Institute of the Americas, n.d.).

The geothermal electricity is produced from the Cerro Prieto Geothermal Power Station in Mexicali, which was the largest geothermal power plant until the introduction of Lardello in Italy and The Geysers in the United States. Currently, the installed capacity is 570 MW; however, the effective capacity is only 340 MW. In 2011, four of the thirteen turbines were decommissioned due to lack of steam, which reduced the original installed capacity of 720 MW, resulting in the plant operating at less than 50% of its original capacity (Institute of the Americas n.d.) (Statista 2024b). Since this is the case, no expansion of geothermal energy is assumed in the modeling.

The total installed capacity and the fractions of each type are shown in Figure 9. As can be seen in the figure, more than 75% of the total installed capacity is based on natural gas combustion, and only a small fraction is generated by solar and wind energy. Turbo gas, internal combustion, combined cycle, and conventional thermal power plants all rely on fossil fuels to generate electricity. These plants typically use a range of fossil fuels, including natural gas, diesel, or oil.

The total electricity generation connected to the grid in the SIBCS 2023 was 15 311 GWh, and similarly to the installed capacity, the majority comes from the combined cycle. The amount of electricity produced using renewable energy sources was 13.9%, where the major contribution was from geothermal energy (SENER n.dB).

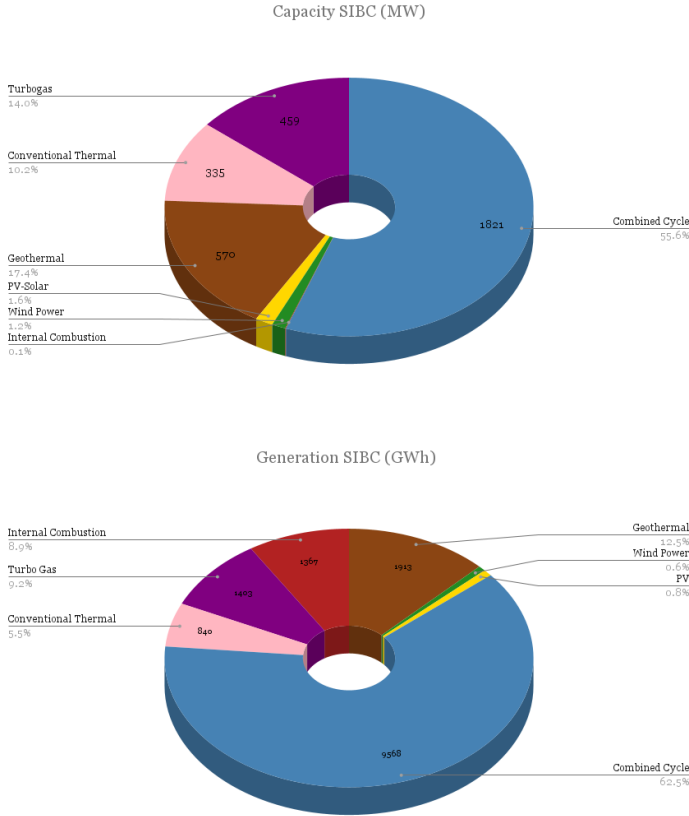


Figure 9: Total installed capacity (upper) and generation in SIBC (lower) divided into energy source 2023. Data from PRODESEN 2024-2038

It should also be noted that the electricity production from internal combustion is unreasonably higher than the installed capacity (1.4 TWh compared to the installed capacity of 2 MW 2023). However, data on electricity generation from PRODESEN 2024-2038 also include power plants that have been tested during 2023. Therefore, in the LEAP model, an additional 0.43 GW of internal combustion has been added, as this is the size of the plant that is being tested according to information from the BC state energy commission (Comisión Estatal de Energía de Baja California, n.d.C).

In BC, there are also several producers of electricity. As mentioned earlier, the national electricity provider CFE is the main actor in the market. However, since the de-privatization of electricity production, several other companies have started producing electricity. In SIBC, as seen in Figure 10, over two thirds of the installed capacity belongs to the CFE, followed by independent production and companies with permits in accordance with the LIE (Ley de la Industria Eléctrica, Electricity Industry Law).

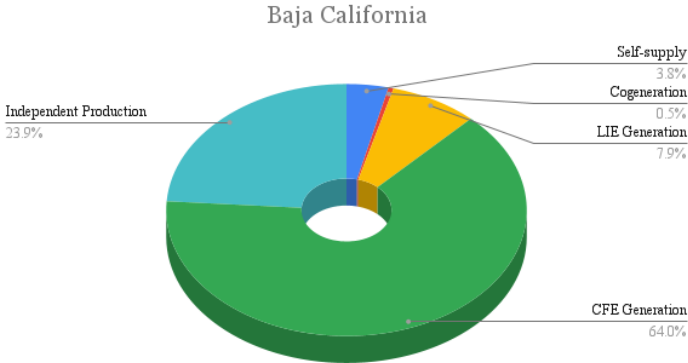


Figure 10: Electricity providers in SIBC. Data from PRODESEN 2024-2038.

4.3 Connection to the United States of America

As mentioned above, SIBC is disconnected from the national grid, however, compared to the two other systems, it's not a completely isolated system since it has connection to the United States electrical system, the Western Electricity Coordinating Council (WECC), making it possible to use import to balance the system (CENACE, n.d.). There are two 230kV transmission lines between the US and the state of BC, one located in the La Rosita-Valle Imperial substation (right) and the second in Tijuana-Otay Mesa substation (left), shown in Figure 11:

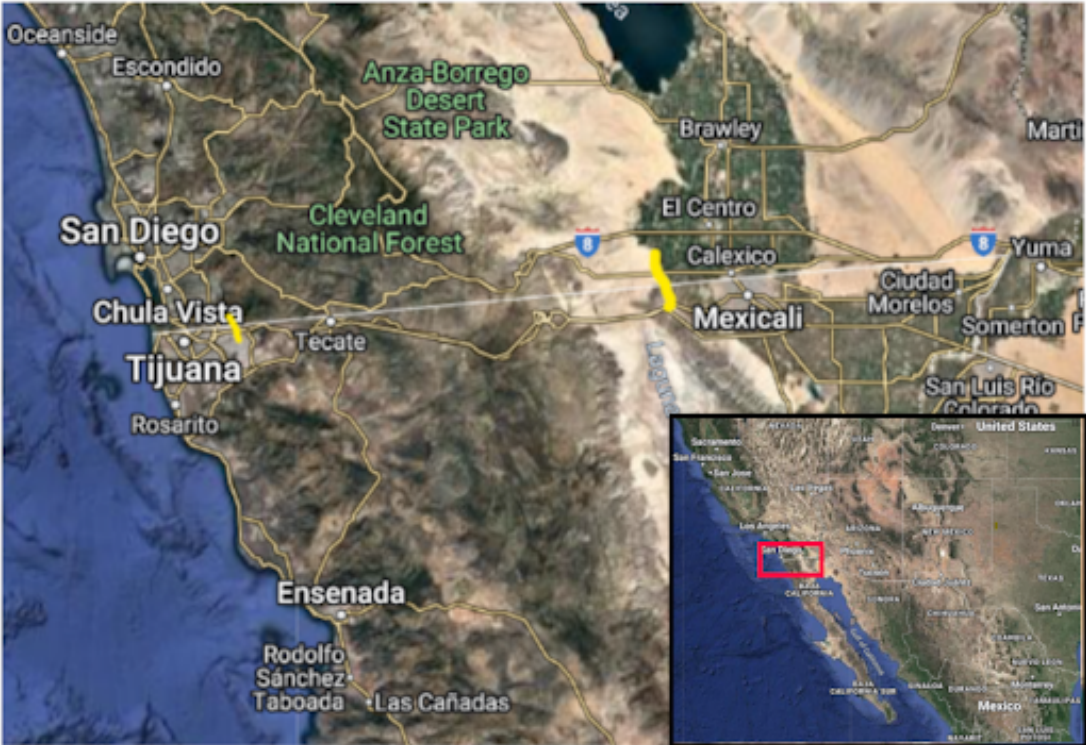


Figure 11: Transmission lines (in yellow) between the U.S. (California) and Baja California. Received from Comision Estatal de Energia Baja California

The current export capacity from BC is 800 MW in total from the transmission points in La Rosita and Tijuana, however, the import differs depending on the season. During the summer BCA has an import capacity of 600 MW and during the winter 408 MW. This is most likely due to the increased need of energy during the summer months in relation to the higher use of air cooling measures. During 2023 BCA imported approximately 1 500 000 MWh and exported 860 000 MWh, which corresponds to a utilization factor of 29.4% and 12.3% (CENACE, n.d.).

To be able to export to the WECC, the producing plants need to have exporting permission and there are currently two combined cycle plants and one wind farm that are approved. The two combined cycle plants are Planta Termoeléctrica La Rosita II and Termoeléctrica de Mexicali, both based in Mexicali with a combined installed capacity of 962 MW. The wind farm is Energía Sierra Juárez located in Sierra de Juárez mountain range close to Tucante, with a capacity of 155 MW, and is the first cross-border wind energy project between Mexico and the United States. The producers which export to WECC are not connected to the rest of the SIBC, and therefore are not included in the model and scenarios (CENACE, n.d.)(Comisión Estatal de Energía de Baja California n.d.B).

4.4 Electricity Production SIBCS

In the system of BCS the main electricity production is located in the southern part, close to the larger cities of Los Cabos and La Paz. The total installed capacity of the system is 1.2 GW, and similarly to SIBC, the main production type is fossil based via turbo gas plants, followed by internal combustion and conventional thermal. Compared to the SIBCS however, the main combustible is diesel and oil and not natural gas, which is imported from the Mexican mainland through the ports of La Paz and Los Cabos. The total installed capacity and the fractions of each type is shown in the Figure 14. As can be seen in the figure, more than 85% of the total installed capacity is produced through the combustion of fossil fuels and only a small fraction is from solar and wind production. Compared to SIBC, there is no geothermal energy production in the SIBCS but the fraction of solar and wind power is larger (SENER, n.d.B).

The total electricity generation connected to the grid in the SIBCS 2023 was 3.2 TWh, and similarly to the installed capacity, the majority is from turbogas and internal combustion. However, the amount produced by turbogas is significantly lower than the amount of installed capacity. While the turbogas is 54% of the total installed capacity, it's only 38.5% of the total electricity generated and internal combustion is 22.5% of the total installed capacity but 34.8% of generated electricity. The amount of electricity that was produced using renewable energy sources was 10.7% from solar and wind energy (SENER n.d.B).

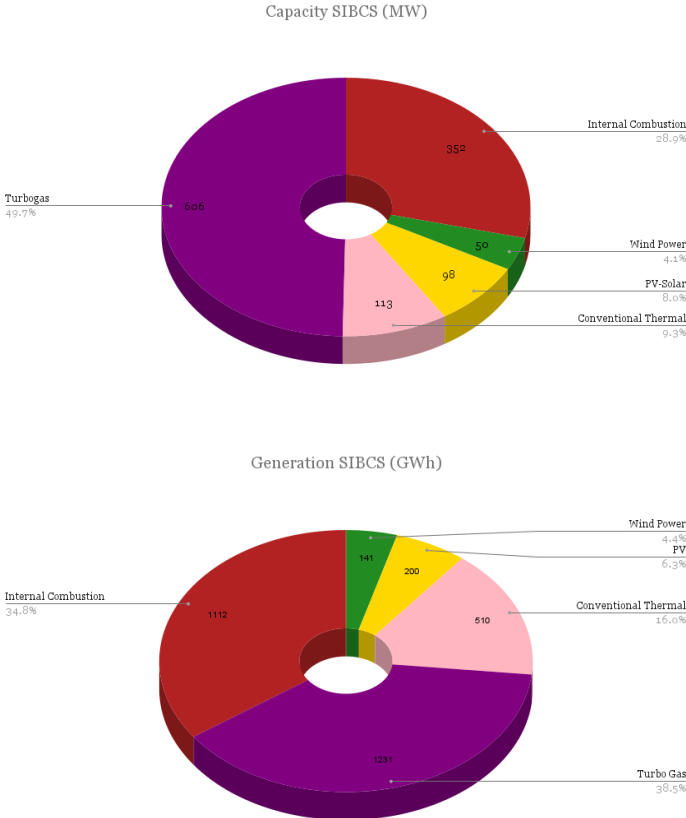


Figure 12: Total installed capacity (upper) and generation (lower) in SIBCS divided into energy source 2023. Data from PRODESEN 2024-2038.

Similarly to SIBC, there are several producers in the system, however a larger amount of the installed capacity is owned by CFE and there are fewer actors on the market (SENER, n.d.B).

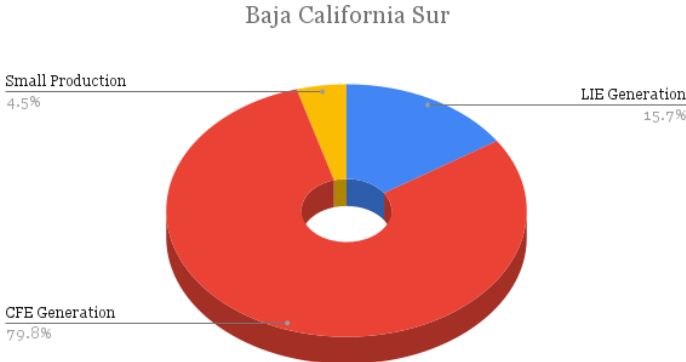


Figure 13: Electricity providers in SIBCS. Data from PRODESEN 2024-2038.

4.5 Electricity Production SIM

In the system of Mulegé the main electricity production is located close to the cities of Vizcaino and Santa Rosalía. The total installed capacity of the system is 134 MW, and compared to SIBC and SIBCS the main source is from internal combustion, followed by turbogas. The total installed capacity and the fractions of each type is shown in the Figure 14. As can be seen in the figure, more than 90% of the total installed capacity is produced through the combustion of fossil fuels and only a small fraction is from solar and geothermal production. In Mulegé all of the installed capacity is owned and operated by the CFE (SENER, n.d.B). The official source material from SENER's ANEXOS PRODESEN 2024-2038 did not provide the installed capacity for the energy system of Mulegé. Therefore, several assumptions were made to estimate this capacity based on the generation data and the existing plants in Mulegé and Baja California Sur.

There were several difficulties when making assumptions of the installed capacity of Mulegé. Three different sources was compared, PRODESEN 2024-2038, PAMRNT 2024-2038 and reports from CERCA. In all three of these cases, there were differences in the data regarding the installed capacity of fossil based energy production. In the end, the data from PRODESEN and PAMRNT was chosen, since the rest of the data was used from there, however it should be noted that the assumed current installed capacity is probably not in accordance with the reality.

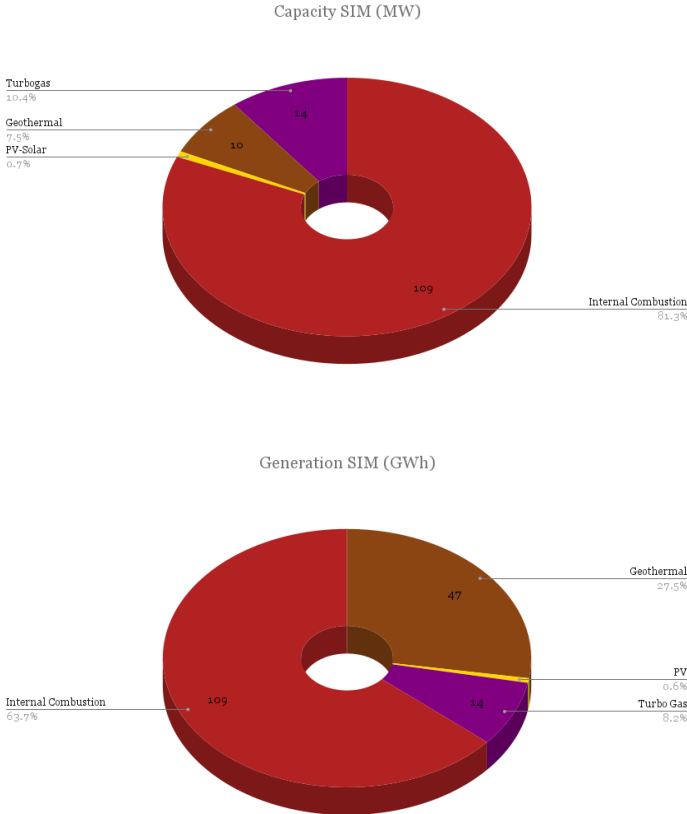


Figure 14: Total installed capacity (upper) and generation (lower) divided into energy source in SIM 2023. Data from PRODESEN 2024-2038.

4.6 Fuel Cost, Wind & Solar Availability and Social Cost of Carbon

To model accurate costs of energy production, fuel costs 2023 and predictions from PAMRNT 2024-2038 was used, see Appendix A for the detailed availability profiles for 2023 for the three regions. In the figure below the change in price for the different fuels are shown.

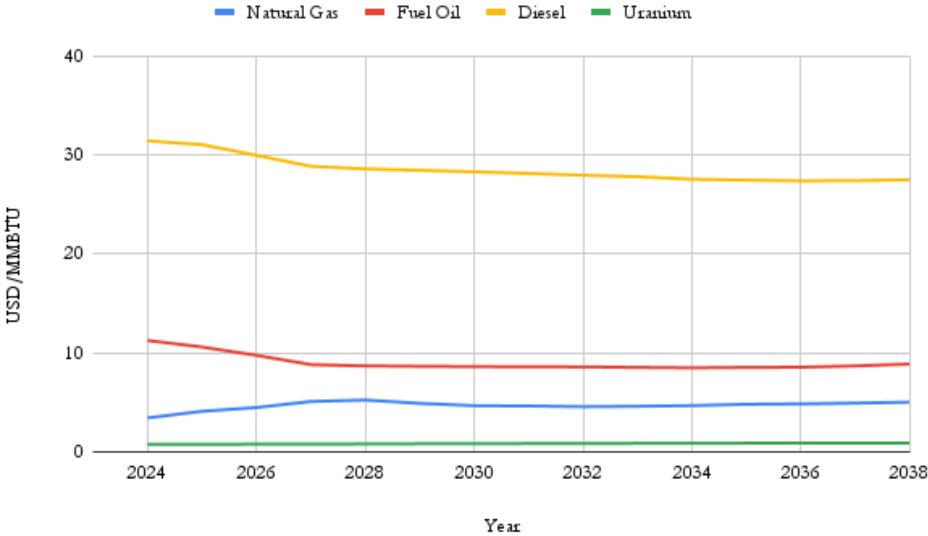


Figure 15: *The change of fuel costs between 2024-2038. The cost of Natural Gas and Diesel are on a national level while the cost of fuel oil is specific to Baja California Sur. Data from PAMRNT 2024-2038*

As shown in Figure 15 above, the prices for diesel and fuel oil are projected to decrease in the coming years, while the price of natural gas is expected to rise. However, by around 2028, most fuel prices are expected to stabilize at values close to their respective long-term averages. These projected changes in fuel prices were provided by SENER, based on various economic scenarios, with the middle value being used for the analysis.

Since wind and solar production is not constant, but rather changes seasonally and daily, the changes in the amount of wind and solar had to be taken into account. Because of the lack of hourly data on wind and solar energy production, weather data from the National Renewable Energy Laboratory in the US (NREL) was used to make estimations. Hourly data on wind speed at 100 meters and the GHI (Global horizontal irradiance) of a point in all three systems was compared to the rated power production of both types. From this an "availability per time-slice" was developed and used in the LEAP modeling to include the variations of solar and wind production; for details see Appendix A.

The yearly average for wind and solar in Baja California and Baja California Sur availability compared to the global capacity factors (CF) are presented in Table 2. As can be seen, the amount of solar power in both areas is much higher than the global average, while the conditions for wind power are worse than the global average.

Table 2: Yearly average of sun and wind availability 2023 compared to global average wind and solar power CF

Area	Solar Availability	On-Shore Wind Availability
SIBC	23.08%	23.82%
SIBCS	26.22 %	14.71%
Global Average CF	16.2% (Statista 2024)	36% (Statista 2024)

The SCC serves as metric when shaping climate policy by representing the monetary value of the societal damages caused by emitting an additional metric ton of CO₂. For more than a decade, governments such as the U.S, Germany and also Mexico have relied on SCC estimates in benefit-cost analyses, informed by insights from climate science, economics, demography, and other fields.

In the United States, the current value for the SCC is set at 51 USD per metric ton of CO₂. This value is used in this study to conduct cost-benefit analyses of various scenarios. However, a report by the U.S. National Academies of Sciences, Engineering, and Medicine (NASEM) presents evidence suggesting that this value may be underestimated. Additionally, an article by Rennert, K., Errickson, F., Prest, B.C. et al. argues that the SCC should be closer to 185 USD per metric ton of CO₂, which would result in a larger increase in the benefits of reducing GHG emissions compared to the currently used value (Rennert, K., Errickson, F., Prest, B.C. et al 2022).

4.7 Distributed Generation

In both SIBC and SIBCS there is assumed distributed generation, which is generated generally from self-production from solar energy, approximately 99.334% according to PAMRNT 2024-2038. When modeling in LEAP, this is assumed to be 100% solar energy and also the cost of production is equal to zero, since this cost is covered directly by the consumer of energy and not by a major producer. In the different scenarios, the distributed generation is assumed to be equal to the development in PAMRNT 2024-2038.

4.8 Storage Option

In this study, two storage options are considered. For all three systems, the potential for expanding lithium-ion (Li-ion) battery storage is included. Li-ion battery storage is currently the most widely used type of energy storage, accounting for the majority of newly installed capacity globally. They remain costly due to the high price of rare metals used in its production. Additionally, the limited availability of these metals raises concerns about future resource scarcity (IEA, n.d.).

In the sensitivity analysis, pumped hydro storage (PHS) is added as an option for long term storage. PHS is currently the most widely used type of energy storage globally but faces challenges, which are mainly geographical. PHS requires a basin large enough, with sufficient difference in altitude to generate substantial energy. Furthermore, it necessitates a significant amount of (fresh) water, which can be a limiting factor in certain regions (IEA n.d.).

4.9 Hydrogen Demand and Electricity Export

The demand for clean hydrogen is anticipated to grow significantly in the coming years, driven by the global transition to low-carbon energy sources. Clean hydrogen primarily exists in two forms: green hydrogen and blue hydrogen. Green hydrogen is produced through electrolysis powered by renewable energy, while blue hydrogen is derived from natural gas, with carbon emissions mitigated through CCS technology (World Resource Institute 2024).

According to McKinsey, the demand for clean hydrogen in the United States is projected to reach 78–93 million tonnes annually by 2050 (McKinsey 2024). In Mexico, demand is expected to grow to approximately 4 million tonnes per year within the same time frame, according to information obtained from INECC/Danish Energy Agency.

The largest production capacity assumed in the study yields an annual output of just under 15,000 metric tonnes. While this does not exceed the demand in either Mexico or the United States, it could still serve as a valuable contribution to the market.

In the study's calculations, a selling price of 32 USD/MWh was used for hydrogen. However, the long-term price of green hydrogen remains uncertain, as the market is still relatively new and not yet fully established. To estimate this selling price, data compiled from the International Council on Clean Transportation (ICCT) and Ahang et al. (2025) were utilized.

4.10 Curtailed Electricity

Curtailed energy refers to the unused electricity generated by renewable energy sources, such as solar and wind, that exceeds the grid's ability to absorb or store it. This phenomenon often arises due to mismatches between renewable energy supply and demand, grid constraints, or limitations in storage capacity. While curtailed energy does not directly contribute to emissions, it represents a loss of potential clean energy that could displace fossil fuel generation. (NREL 2014)

As the share of renewables increases, addressing curtailment becomes crucial for maximizing their efficiency and cost-effectiveness. Solutions such as expanding grid infrastructure, improving energy storage technologies, and implementing demand-side management can help minimize curtailment and enhance the overall integration of renewable energy into the system.

5 Results

In the modeling of BC, BCS, and Mulegé as isolated energy systems, it becomes clear that each region exhibits distinct characteristics, challenges, and opportunities in energy generation. The energy mixes and technologies deployed vary, shaped by factors such as geographical location, availability of natural resources, existing infrastructure, and local electricity demand.

As described in Section 3.7, key indicators including generation, installed capacity, costs, emissions, and curtailed energy reveal how these regions manage their energy systems. Each isolated system relies on a tailored combination of renewable energy sources, such as solar and wind power, supported by storage technologies and, in some cases, backup generation from fossil fuels to ensure grid stability and year-round reliability. These differences highlight the importance of region-specific strategies for balancing sustainability, economic feasibility, and energy security.

5.1 Baja California as an Isolated System

The following section presents the results of the SIBC scenarios modeled as an isolated system, offering insights into how key system indicators respond to different assumptions.

5.1.1 Change in Annual Generation and Installed Capacity

As can be seen in all three scenarios, there is a large expansion of solar power compared to the Baseline, especially in the fully renewable scenarios. Furthermore, in both REN and EXP, the renewable energy mix is more diverse, with a larger expansion of wind power, which, with the addition of batteries, compensates for the fossil-based energy generation.

Regarding the total annual production, it is important to note that in modeling the Baseline scenario, production appears insufficient to meet the required demand. This discrepancy may arise from the program's inability to model storage options without incorporating optimization but could also be a shortage in the total installed capacity, which is shown in Figure 16. Overproduction occurs in the two renewable scenarios, which is linked to the introduction of batteries into the system. The storage process involves minor energy losses, necessitating a slight annual overproduction to ensure the system's needs are fully met.

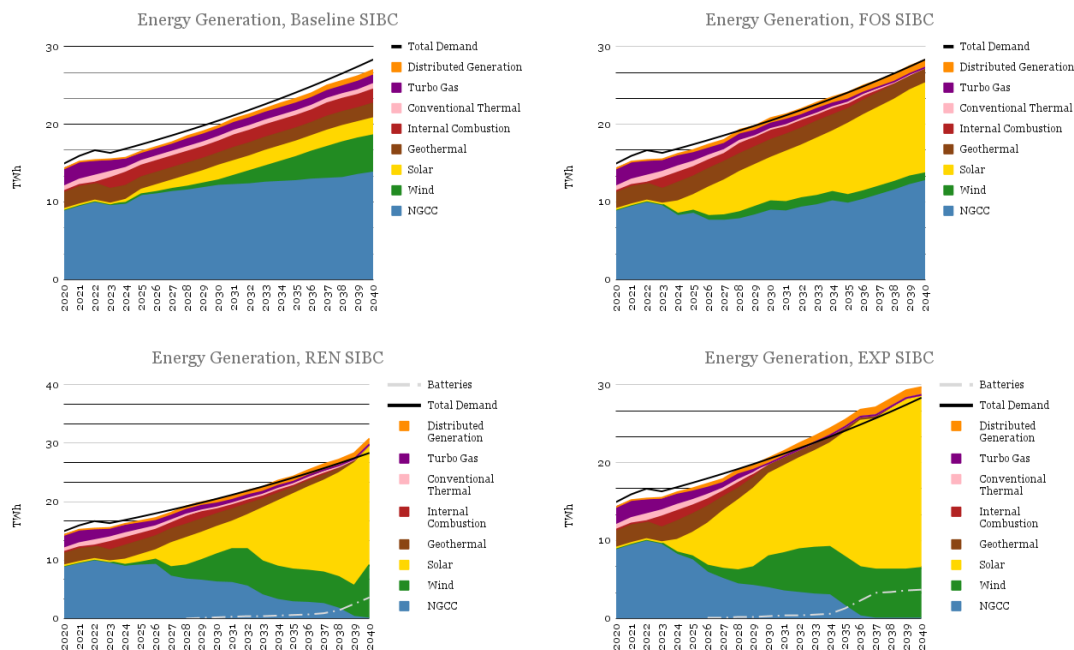


Figure 16: *Energy Generation 2023-2040 Baseline (u.left), FOS (u.right), REN (l. left) and EXP (l. right). The installed capacity of batteries (GW) in the systems are marked as the grey semi-line*

The FOS scenario in SIBC demonstrates a sustained and increasing reliance on combined-cycle power generation, which accounts for nearly half of the energy generation by 2040, while other fossil-based production declines over time. Notably, solar expansion is the largest in the system, contributing approximately 40% of total generation in 2040 and compared to Baseline, the share of wind is instead lower, 3.5% (1 TWh) versus 17.8% (4.8 TWh). The FOS scenario also features the highest share of geothermal energy compared to scenarios with a stronger focus on renewables. In FOS, geothermal power accounts for 6.7% (1.9 GWh) of total generation, whereas in the REN and EXP scenarios, it contributes only 0.3% (0.1 GWh).

In the REN scenario, a significant co-expansion of solar and wind power occurs between 2026 and 2032. Solar power continues to expand through 2040, enabling the system to reach 100% renewable energy. Battery storage is introduced in 2028, with rapid growth in the last three years, resulting in an installed capacity of 3.6 GW by 2040. In the EXP scenario, the expansion of batteries occurs earlier, where the larger expansion is leading up to 2037 instead.

Regarding generation, the EXP scenario is similar to the REN scenario but reaches 100% renewables by 2037, with a sharper increase of solar power compared to wind energy, which expands at a lower pace. However, the peak in wind power expansion occurs earlier in the EXP scenario, with production stabilizing at 6–6.5 TWh from 2033 to 2040. This is reflected in the installed capacity, which remains constant at 3.4 GW from 2034, compared to a maximum of 4.4 GW in REN by 2040. Wind power’s total share in the EXP scenario is lower—21.9% (6.5 TWh) compared to 29.9% (9.2 TWh) in REN—offset by higher solar power production, which contributes 22.1 TWh in EXP versus 20.5 TWh in REN.

The changes in installed capacity are summarized in Figure 17. As expected, the two renewable scenarios require higher installed capacities due to the variability of renewable energy production. The EXP scenario, which achieves 100% renewables by 2037, initially exhibits a larger capacity increase. By 2040, both REN and EXP scenarios converge on similar total installed capacities, with REN exceeding EXP by 400 MW.

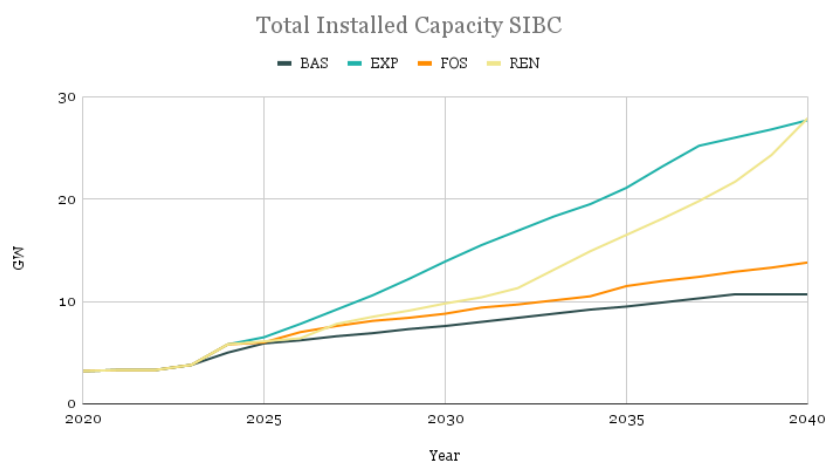


Figure 17: *The change in the total amount of installed capacity of the different systems in SIBC*

The two scenarios that retain fossil-fuel technologies have significantly lower total installed capacities, with the Baseline scenario having the lowest. However, as noted, energy production in the Baseline scenario falls short of demand in 2040, indicating that planned installed capacity is insufficient to meet the system’s increased requirements.

5.1.2 Weekly Generation 2023 vs 2040 by Day and Night

Figure 34 and 19 depict the differences in weekly energy generation and the variation between daytime (06:00–18:00) and nighttime (18:00–06:00) energy production 2023 and for each scenario in 2040.

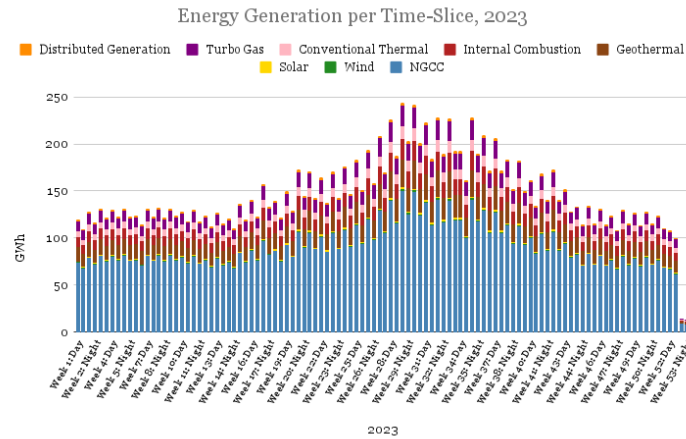


Figure 18: Energy Generation per Time Slice in 2023 in SIBC

Comparing the time slices during a year, there are several things that can be pointed out. Firstly, even looking at Baseline compared to 2023, the share of renewable energy is significantly higher and during the winter months, where the amount of renewable generation covers almost half of the whole system. Although, the yearly average of renewable use is only 35.6%.

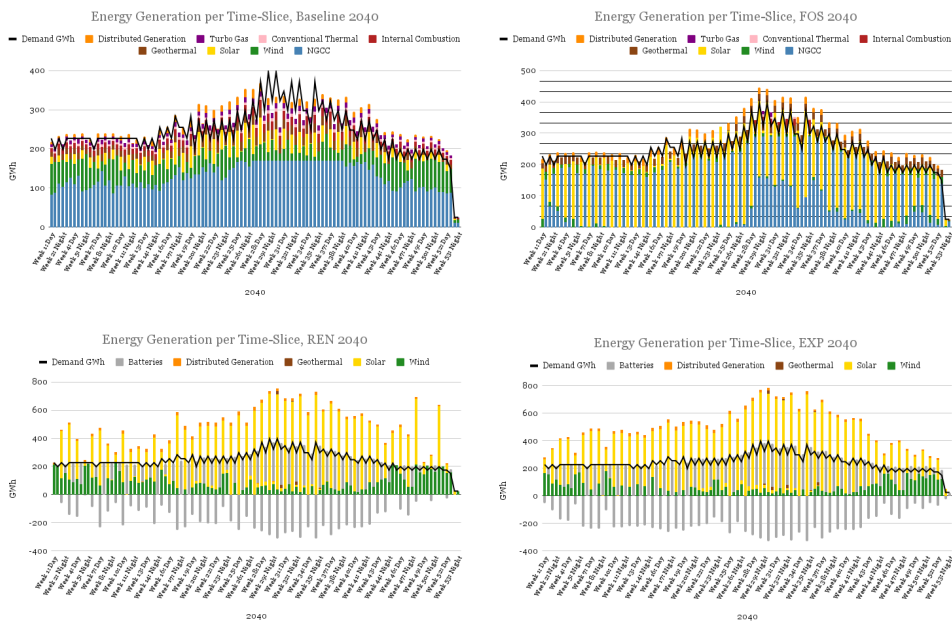


Figure 19: Energy Generation per Time Slice in 2040 in SIBC for Baseline (u.left), FOS (u.right), REN (l.left) and EXP (l. right)

Looking at FOS, even with the continuation of fossil based technologies (mainly combined cycle), there is still a high prevalence of renewable energy. Notably during the winter months, the production from solar, wind and geothermal power is enough to sustain the whole system during the days. However, the smaller amount of wind power, which can also produce energy during the night, in the system increases the need for combined cycle. Resulting in the share of renewable energy being significantly smaller, around 25%, following, the yearly average of renewables being around 54%. The other fossil based technologies: turbo gas, internal combustion and conventional thermoelectric are used during very few periods during the summer when the demand for energy is especially high or the production from renewable energy sources is too low.

In the two scenarios with 100% renewable energy sources, energy storage in the form of batteries is introduced. Positive values in the battery column indicate energy discharge to the system, while negative values represent charging. In both the REN and EXP scenarios, which feature significant solar power generation, batteries are primarily charged during the day when solar overproduction is more likely. This stored energy is then discharged at night, when solar production is minimal, and energy demand is higher. This pattern is particularly pronounced during summer, as wind production is lower during this period.

In continuation, the EXP and REN scenarios are very similar, especially the lack of geothermal energy and as mentioned above, the high dependence on solar energy. However, a noticeable difference lies in the share of wind energy. During the winter months, the greater contribution of wind energy reduces the REN's reliance on storage at night, as higher wind production better meets the demand during these hours.

5.1.3 Total Cost of Energy Production and Cost per Energy Produced

The figures below illustrate the differences in production costs between 2023 and 2040 for each scenario. In this analysis, production costs encompass all expenses associated with electricity generation, including fuel costs, operation and maintenance (O&M) expenses, and capital costs (such as the initial investment in power plants and equipment). By incorporating capital costs, both fixed and variable expenses are accounted for in the overall calculation.

It is important to note that transmission grid expansion costs are excluded, as they represent separate infrastructure expenditures and fall outside the scope of production costs. This analysis focuses specifically on the operational aspects of power generation. As a result, the approach provides a comprehensive view of the costs directly related to electricity production, covering both operational expenses and the capital investments required to establish and sustain energy production technologies.

Additionally, given the variations in the amount of energy produced across scenarios, a comparison of costs per unit of energy produced has also been conducted.

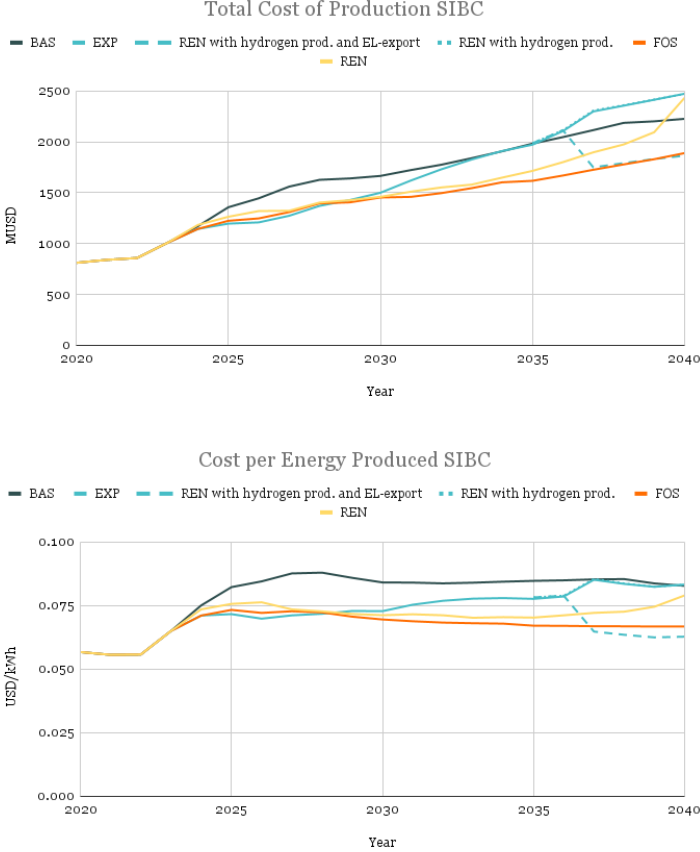


Figure 20: Annual cost of production for each scenarios (upper) and Annual cost per energy produced (lower) from 2020 to 2040 in SIBC

Regarding annual production costs, as shown in the figure below, all scenarios project higher annual production costs in 2040 compared to 2023. This outcome is expected, as the investment cost increases alongside the growth in total installed capacity.

The Baseline scenario is the most expensive option for several years, even though it looks like the system will not be able to meet the expected demand growth. Overall, FOS is the cheaper option, mainly due to the battery storage having high capital costs compared to other technologies.

The scenarios with the highest costs are REN and EXP, likely due to the need for a larger amount of installed capacity. However, in the early years, the scenarios exhibit similar production costs to Baseline and FOS due to the lower capital costs of renewable energy, mainly solar power, compared to the expansion of fossil-based technologies. The reduction of fixed O&M costs, fuel costs and most likely, the lack of battery storage keep the total production cost at a lower level.

In the EXP scenario, preliminary calculations were conducted to evaluate the addition of hydrogen production and electricity exports. As illustrated in the figure, exporting curtailed energy yields the largest cost reduction (income) compared to focusing on hydrogen production, based on the study's assumptions. Producing and selling green hydrogen results in a break-even outcome, with no significant impact on production costs. In contrast, exporting 13% of the curtailed energy from the year 2037 emerges as the more cost-effective option. The assumptions surrounding hydrogen production and energy export will be further analyzed in the discussion.

Regarding cost per energy produced, there is a large increase leading up to 2025 in all scenarios, after which most are stable until batteries are introduced in the renewable scenarios. In the other two scenarios there is a trend of the cost decreasing over time after 2025, however the Baseline is the most costly option over time.

5.1.4 Total Emissions from Energy Production and Emissions per Energy Produced

As shown in the figure below, initially emissions from the energy production decrease in all scenarios compared to the Baseline, where total emissions instead increase. The first few years the REN scenario has the slowest decrease in total emissions, however, after 2027 and onwards the scenario with highest emissions is FOS, which is not surprising. In 2040 FOS have about the same amount of emissions compared to 2023 - 5380 compared to 5930 kTonnes CO₂-eq per year (9.2% decrease). However, compared to Baseline, the total emission have decreased by 2230 kTonnes CO₂-eq per year, which is a reduction of 29.3%. It should be noted that the emissions in FOS are in an increasing trend after 2035, unsurprisingly considering that the system is assumed to be constantly increasing.

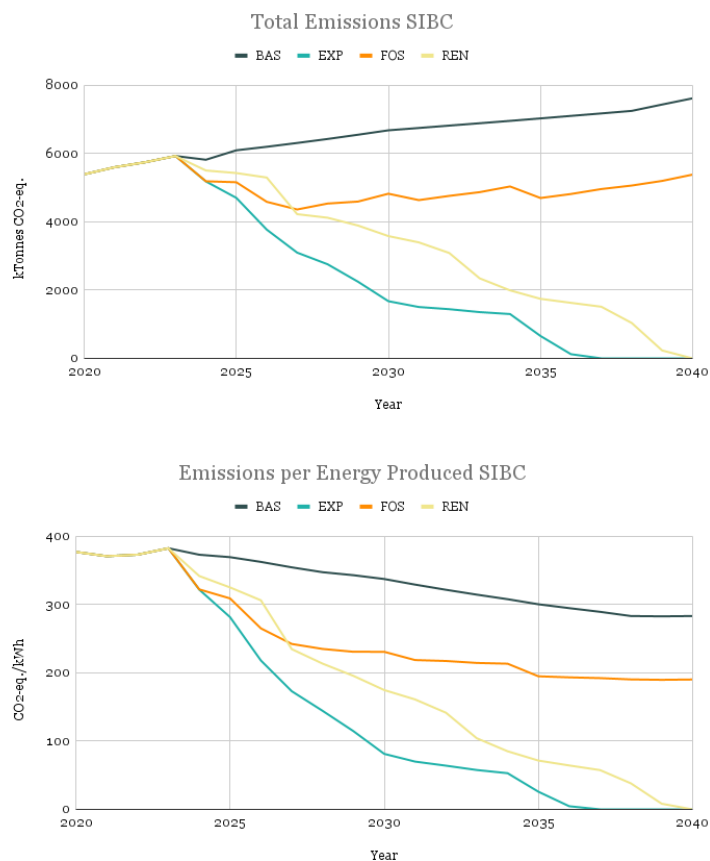


Figure 21: Emissions for each scenario (upper) and Emissions per Energy Produced in SIBC from 2020 to 2040 (lower)

In all scenarios, including Baseline, the emissions per energy produced are decreasing until 2040, where the fastest decrease is in the EXP scenario and the slowest in baseline. FOS seems to be stabilizing around 200 g CO₂-eq/kWh, which is almost half of the 2023 emissions and a third of the emissions from Baseline.

5.1.5 Annual and Weekly Curtailed Energy

The results of the modeling regarding curtailed energy align with the background information: the introduction of variable energy sources into the system leads to an increase in curtailment. In both the EXP and REN scenarios, annual curtailment is significantly higher compared to scenarios with lower shares of renewable energy. For both scenarios the steepest increase of curtailed energy is when the expansion of renewable energy is the largest and in the EXP scenario, some of the curtailed energy is used in hydrogen production, resulting in the curve flattening somewhat after 2035.

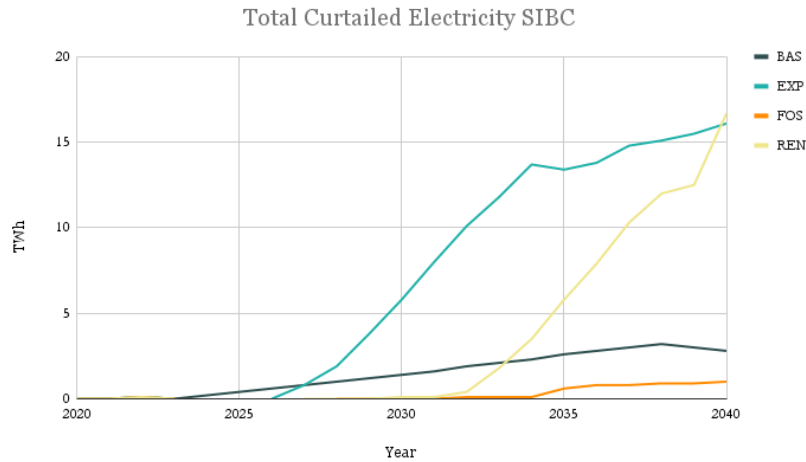


Figure 22: Total Curtailed Electricity 2024 to 2040 in SIBC

As shown in the figures with weekly curtailed energy below, curtailment is highest during the winter months when demand is lower and almost negligible during the summer months when demand peaks. Notably, the EXP scenario exhibits a higher level of curtailed wind energy, despite having a smaller share and overall amount of wind power in the system.

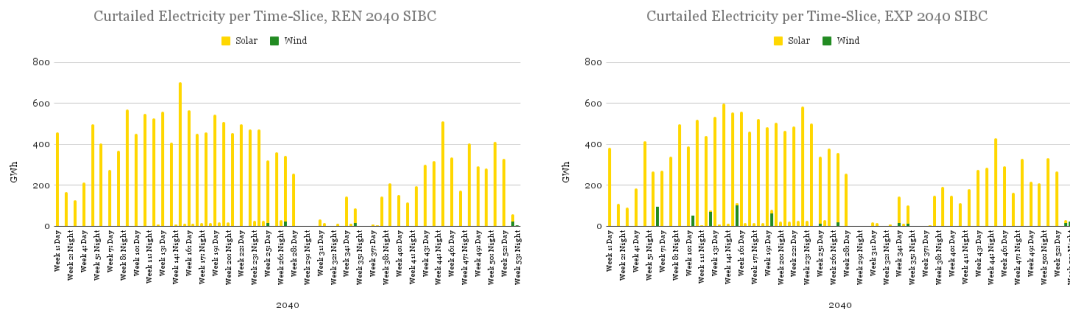


Figure 23: Total Curtailed Electricity 2024 to 2040 in SIBC

5.2 Baja California Sur as an Isolated System

For SIBCS, the trends largely mirror those of SIBC, though some notable differences exist. The gap between demand and energy generation in Baseline is even more substantial in SIBCS and regarding the total emissions from the system and the amount of wind energy is significantly lower.

5.2.1 Change in Annual Generation and Installed Capacity

Similarly to SIBC, in the Baseline, the growth of renewable energy is slower compared to the other optimized scenarios, as can be seen in Figure 24 below. The system continues to rely on fossil fuels for electricity, particularly from turbo gas plants but also a large amount from internal combustion. There are two major differences in the Baseline compared to SIBC; one, wind power is much less implemented into the system and basically only solar is expanded until 2040. Secondly, there is 100 MW of nuclear added to the system by 2040. As mentioned above, nuclear energy is not considered in the other scenarios and will therefore stand out compared to the rest of the results.

In the FOS scenario, turbo gas becomes the most prominent energy source followed by solar power. As in SIBCS, the share of renewables increases in FOS compared to the Baseline by 2040, where 43.1% (2.6 TWh) in FOS is renewable compared to 30.8% (1.2 TWh). Comparing the amount of energy produced it's almost the double in FOS compared in the Baseline even though there is only about 10% difference in the share of renewables. This is due to the generation in Baseline being significantly lower, as can be seen as the gap between generation and demand is quite large.

As discussed in SIBC, the Baseline production shortfall could be due to limitations in modeling storage without optimization but could also be because of lack of planning in regards to increasing demand. In contrast, but similarly to SIBC, the REN and EXP scenarios exhibit overproduction to offset storage as can be seen in the figures.

In the REN and EXP the prevalence of wind power is considerably lower compared to SIBC. In 2040, only 8.4% respectively 7.5% of the total energy produced is from wind power, which is 13.5-22.5 percentage points less difference compared to SIBC.

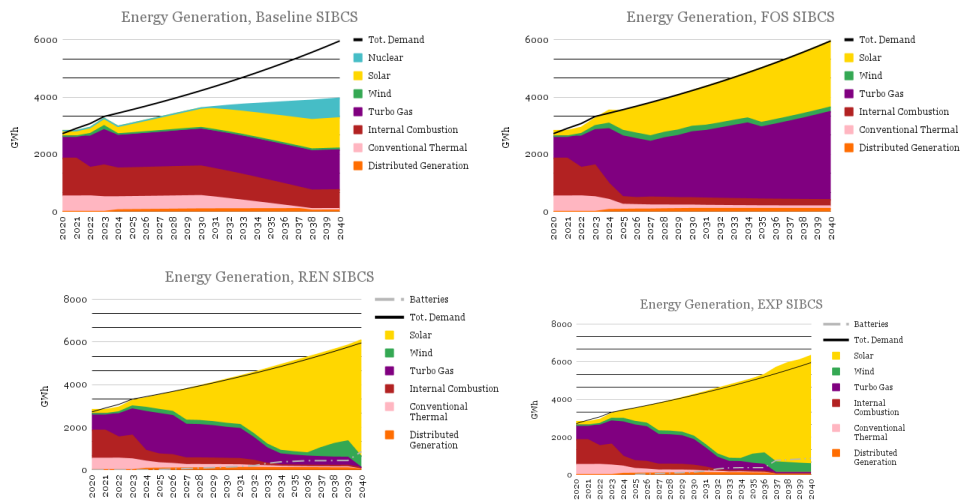


Figure 24: Energy Generation 2023-2040 Baseline (u.right), FOS (u.left), REN (l. left), EXP (l. right). The installed capacity of batteries (MW) in the systems are marked as the grey semi-line

Akin to SIBC, the changes in installed capacity vary across different scenarios as shown in the figure below. Not unexpected, the two renewable scenarios require higher installed capacities due to the variability of renewable energy production. The EXP scenario shows the largest increase in capacity initially, as also shown in SIBC but contrary to SIBC, EXP has the highest amount of installed capacity (around 200 MW more) instead of REN. In the EXP scenario, which adds additional capacity to meet the zero-emission target by 2037 ensuring that the system remains fully renewable while accommodating fluctuations in energy supply and demand.

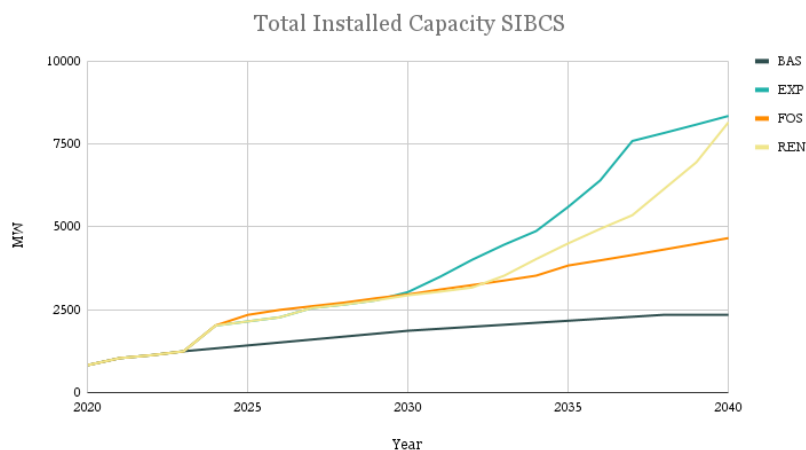


Figure 25: The change in the total amount of installed capacity of the different systems in SIBCS

In contrast, the scenarios that continue to use fossil fuels show significantly lower total installed capacities, with the BAS scenario having the smallest. When comparing the changes in total installed capacity across the various scenarios, it is most likely that the BAS scenario’s planned capacity and generation are inadequate to meet demand by 2040, similarly to SIBC.

5.2.2 Weekly Generation 2023 vs 2040 by Day and Night

The figures below depict the differences in weekly energy generation and the variation between daytime (06:00–18:00) and nighttime (18:00–06:00) energy production 2023 and for each scenario in 2040. Notably, in the Baseline scenario, peak demand during the summer months exceeds generation capacity by far, resulting in an inability to meet the required demand.

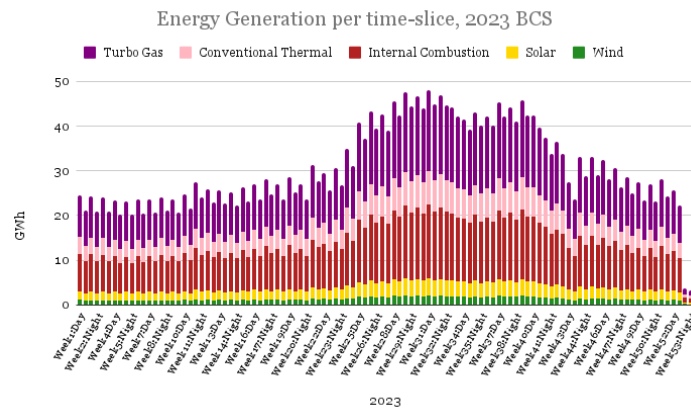


Figure 26: Energy Generation per Time Slice in 2023 in SIBCS

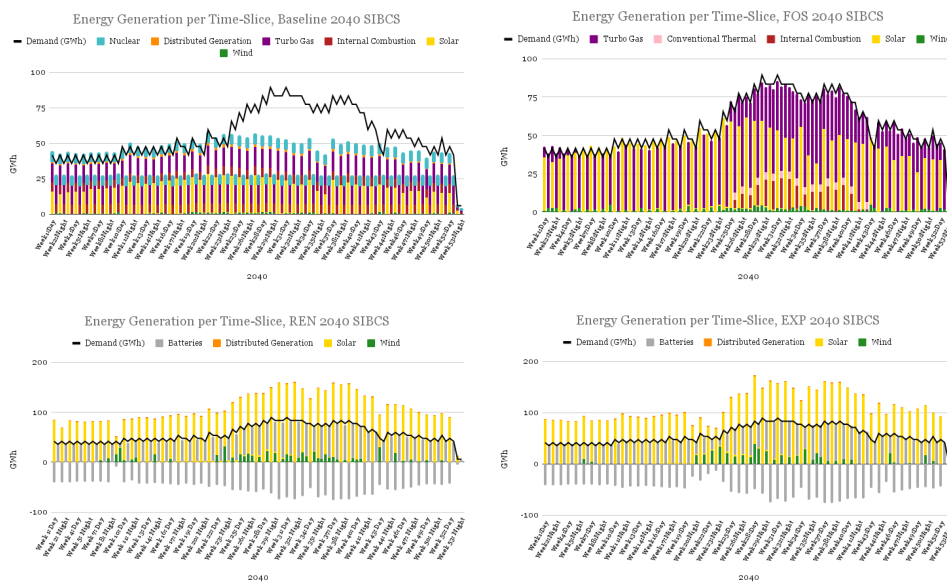


Figure 27: Energy Generation per Time Slice in 2040 in SIBCS for Baseline (u.left), FOS (u. right) and REN (l.left) and EXP (l. right)

In the FOS scenario, daytime energy generation is predominantly from solar power, while turbo gas plants is the main supply of energy at night. However, in contrast to SIBC, the low amount of wind power and lack of geothermal power in FOS, results in the amount of renewables during the night being only 7%, which is much lower compared to the 25% in SIBC. This further shows in the annual share of renewables being more than 10 percentage points lower in FOS SIBCS than in SIBC. However, similarly to SIBC, the reliance on fossil fuel plants, especially turbo gas during summer peaks, is also higher due to the increased demand.

The two zero-emission scenarios, REN and EXP, both feature energy mixes dominated by solar power and battery storage. However, the key difference lies in the decreased share in energy production from wind production in both scenarios compared to SIBC.

5.2.3 Total Cost of Energy Production and Cost per Energy Produced

As shown in Figure 28 below, contrary to SIBC the total cost of energy production is close to constant with a much smaller increase for all scenarios. However, around 2032, similar to in SIBC, the renewable scenarios increases an substantial amount. By 2040 compared to 2023 all SIBCS scenarios project higher annual production costs

Comparing the different scenarios, there are several trends that are similar to SIBC. The BAS scenario remains the most expensive for several years, despite its inability to meet the projected demand growth, until declining somewhat by 2040. Especially when comparing cost per produced energy. The FOS scenario, on the other hand, is more cost-effective regarding the total cost, mainly due to the high capital costs of battery storage. The REN and EXP scenarios, which require larger installed capacities seen in Figure 25, continues to have the highest costs.

As in SIBC, calculations were carried out to evaluate the impact of hydrogen production and electricity exports. As seen below, exporting electricity provides the greatest cost reduction and in SIBCS when around 15% of the annual curtailed is exported, compared to using hydrogen production for profit. Producing and selling green hydrogen thus continues to result in minimal impact on overall production costs.

When examining the cost per unit of energy produced (shown below to the right), all scenarios show a reduction in costs by 2040 compared to 2023. Notably, the difference in cost between the Baseline and the optimized scenarios is substantial for several more years than in SIBC. Although, the EXP scenario differs slightly due to the earlier target for achieving zero emissions, which leads to higher costs associated with faster capacity expansion and the integration of storage solutions.

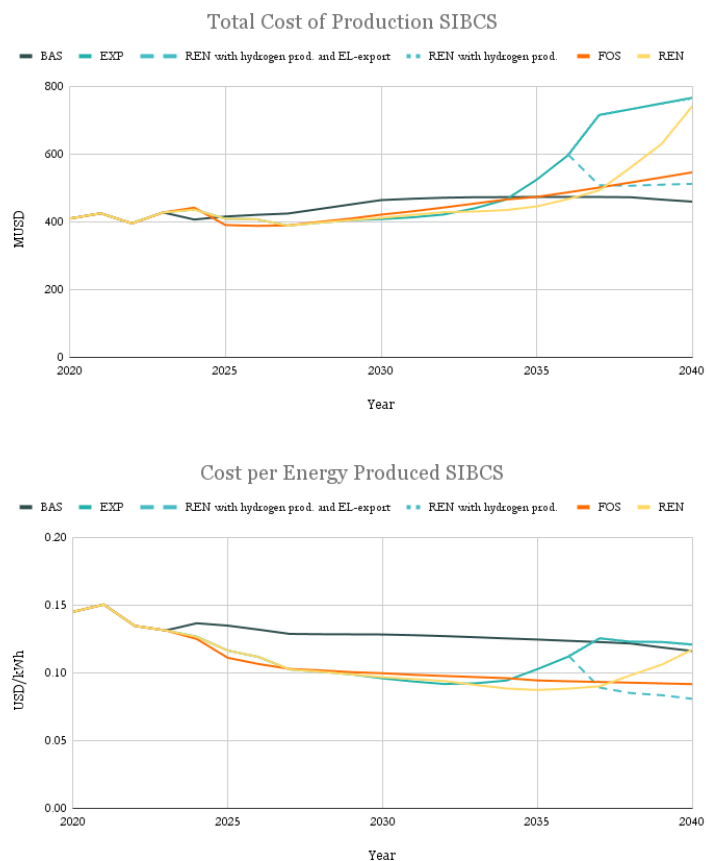


Figure 28: Annual cost of production for each scenarios (upper) and Annual cost per energy produced (lower) from 2020 to 2040 in SIBCS

5.2.4 Total Emissions from Energy Production and Emissions per Energy Produced

As illustrated below, the total emissions of the energy production in the scenarios decrease over time, excluding FOS. After 2030, FOS becomes the highest emitter and by 2040, FOS emissions are 2 420 kTonnes CO₂-eq, compared to 1 960 kTonnes CO₂-eq in 2023 (23.5% increase). The emissions in the EXP scenario are decreasing faster than in the REN scenario. In the BAS scenario, emissions decrease 1 430 kTonnes CO₂-eq in 2040 (27.1% decrease) compared to 2023.

In the figure below, to the right, emissions per unit of energy produced decrease across all scenarios. FOS and BAS show the smallest reductions, while REN and EXP experience a faster decline, similar to the trends in total emissions.

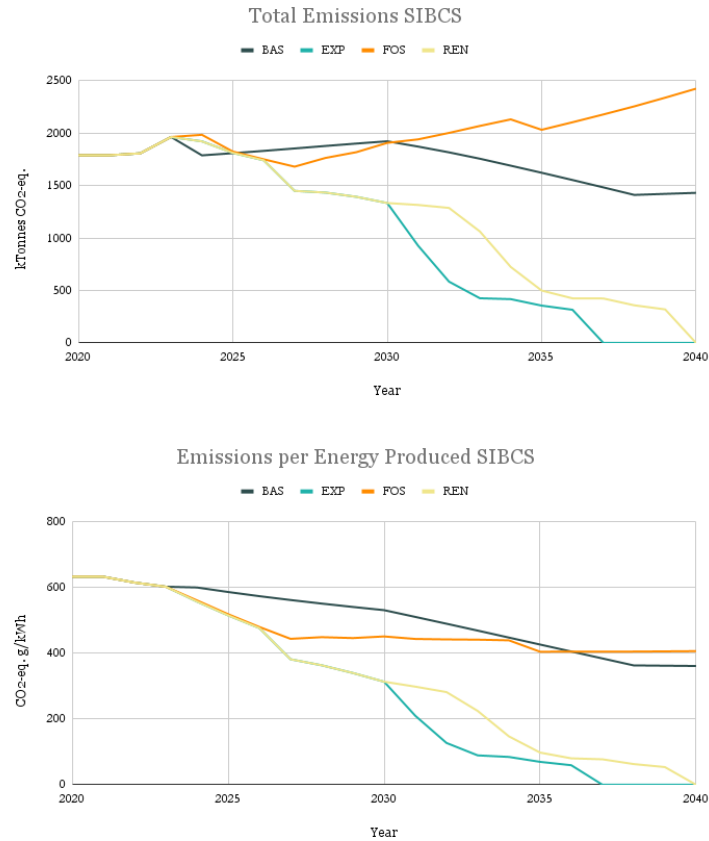


Figure 29: Emissions for each scenario (upper) and Emissions per Energy Produced in SIBCS from 2020 to 2040 (lower)

5.2.5 Annual and Weekly Curtailed Energy

The modeling results for curtailed energy in the SIBCS region follow similar trends to those seen in SIBC. However, in SIBCS, energy curtailment begins later, around 2030. The introduction of variable renewable energy sources leads to an increase in energy curtailment. In both the EXP and REN scenarios for SIBCS, annual curtailment is significantly higher compared to scenarios with a lower share of renewable energy. As in SIBC the steepest increase in curtailed energy occurs when renewable energy expansion is at its peak, just before substantial battery storage is introduced.

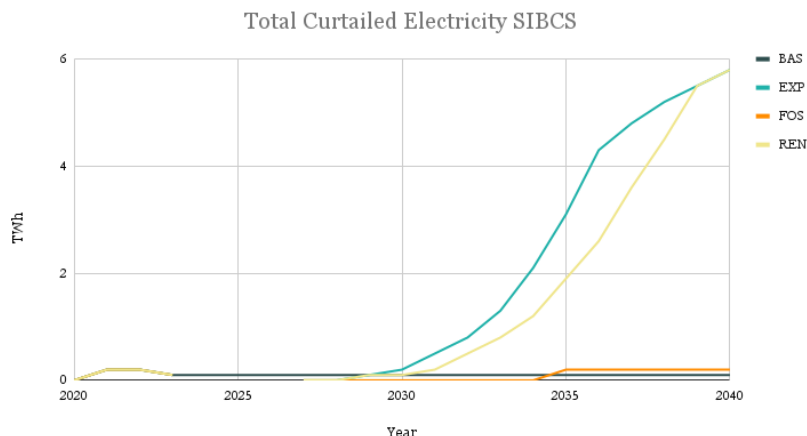


Figure 30: Total Curtailed Electricity 2020 to 2040 in SIBCS

As demonstrated in the figures for weekly curtailed energy below, curtailment is highest during the winter months when demand is lower, while it is almost negligible during the summer months when demand peaks. Notably, even though the share of wind is lower in the energy production in SIBCS compared to SIBC, the occurrence of curtailed wind power is higher.

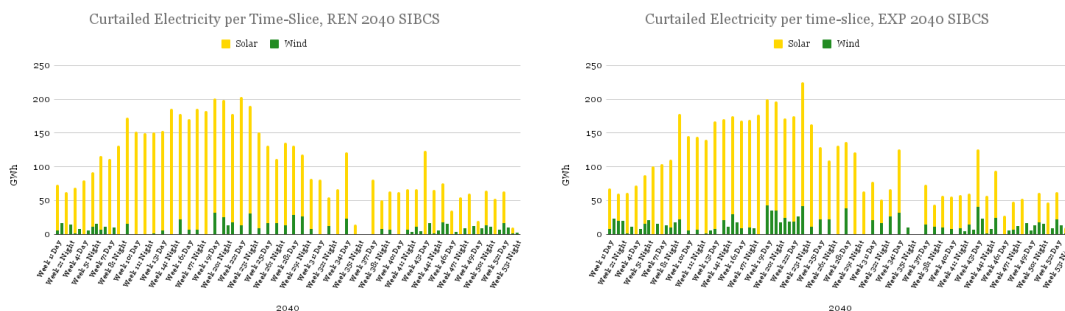


Figure 31: Total weekly Curtailed Electricity 2040 in SIBCS

5.3 Mulegé as an Isolated System

The biggest difference compared to the two other systems is that in the Baseline scenario there is a major capacity addition of sun, resulting in the Baseline in SIM being an outlier compared to the other areas.

5.3.1 Change in Annual Generation and Installed Capacity

Notably, the diversity in energy technologies in Mulegé is much smaller compared to the previous systems. Here only solar, geothermal, internal combustion and turbo gas is present.

As shown in the following figures, the Baseline exhibits a significant increase in renewable energy, reflecting similar trends to those observed in both the SIBC and SIBCS scenarios, though to a much greater extent, where the amount of solar is 51.5% in 2040. Significantly, the generation in the Baseline is enough to meet the demand, which in contrast to the other systems. Similarly to SIBCS, the major fossil based energy production is from turbo gas.

Similar to the other areas, in the FOS scenario, there is a high increase in solar generated energy, but also an increase in the amount of electricity produced from geothermal energy compared to the Baseline, which is 52.1 GWh (22.1%) compared to 23.7 GWh (10.2%).

In the last two scenarios, REN and EXP, the majority of energy generation comes from solar power, highlighting the region’s significant potential for solar energy deployment. Similarly to SIBC, in both REN and EXP the electricity generated from geothermal power is significantly lower than in FOS and Baseline, about 2.1% (5.1 GWh) and 2.0% (5GWh) respectively of total generation. Also in SIM, there is overproduction the last years, when storage is sufficiently implemented.

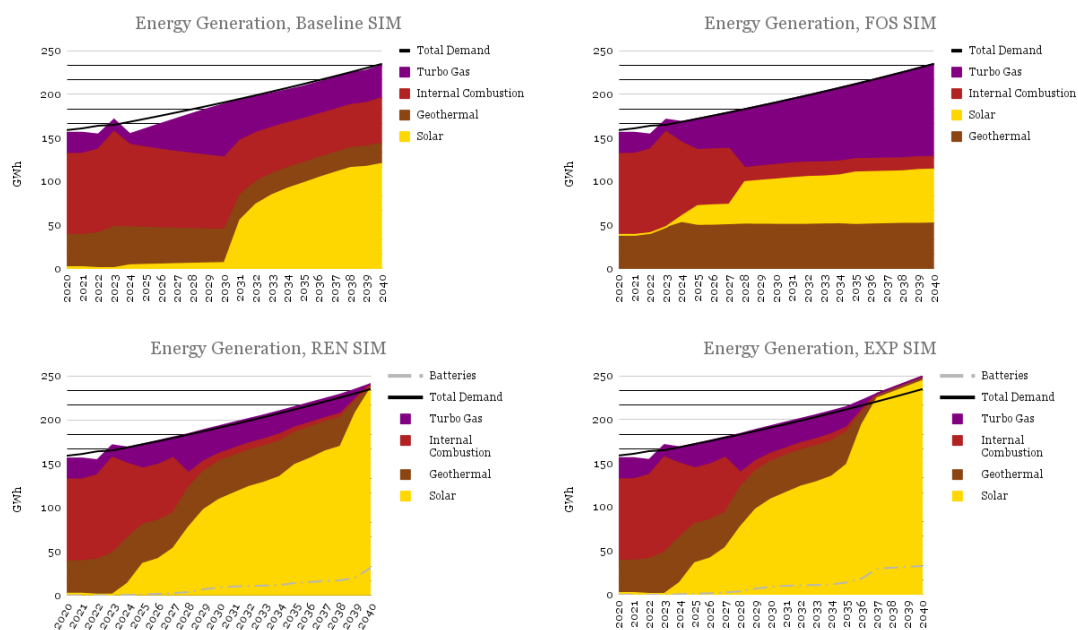


Figure 32: Energy Generation 2020-2040 Baseline (u.right), FOS (u.left), REN (l. left), EXP (l. right). The installed capacity of batteries (GW) in the systems are marked as the grey semi-line

A large contrast to the other areas is in SIM, the total installed capacity in Baseline is the highest. However, similarly to SIBC and SIBCS FOS has the lowest amount of installed capacity until 2040 although all scenarios are very similar until 2035 when EXP increases and later at 2038 when REN increases. In 2040, EXP has around 10 MW more installed capacity than REN.

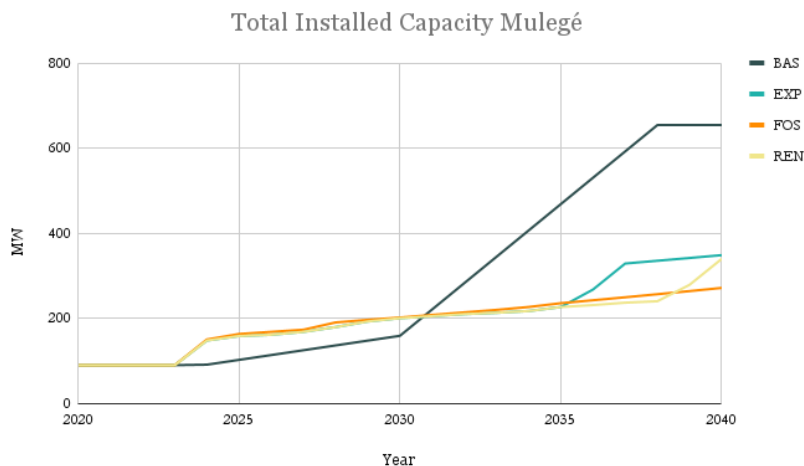


Figure 33: The change in the total amount of installed capacity of the different systems in Mulegé

5.3.2 Weekly Generation 2023 vs 2040 by Day and Night

The figures below depict the differences in weekly energy generation and the variation between daytime (06:00–18:00) and nighttime (18:00–06:00) energy production 2023 and for each scenario in 2040.

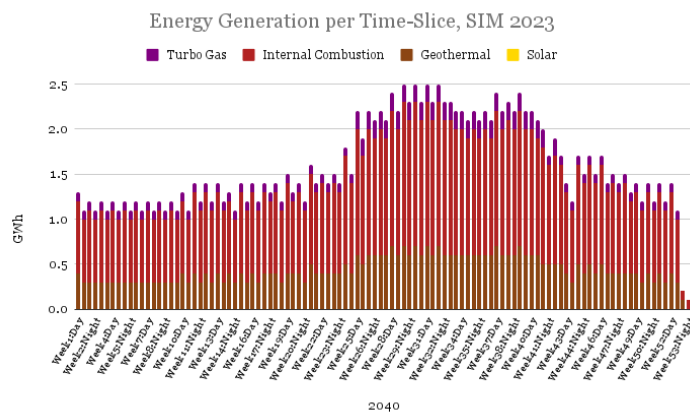


Figure 34: Energy Generation per Time Slice in 2023 in SIM

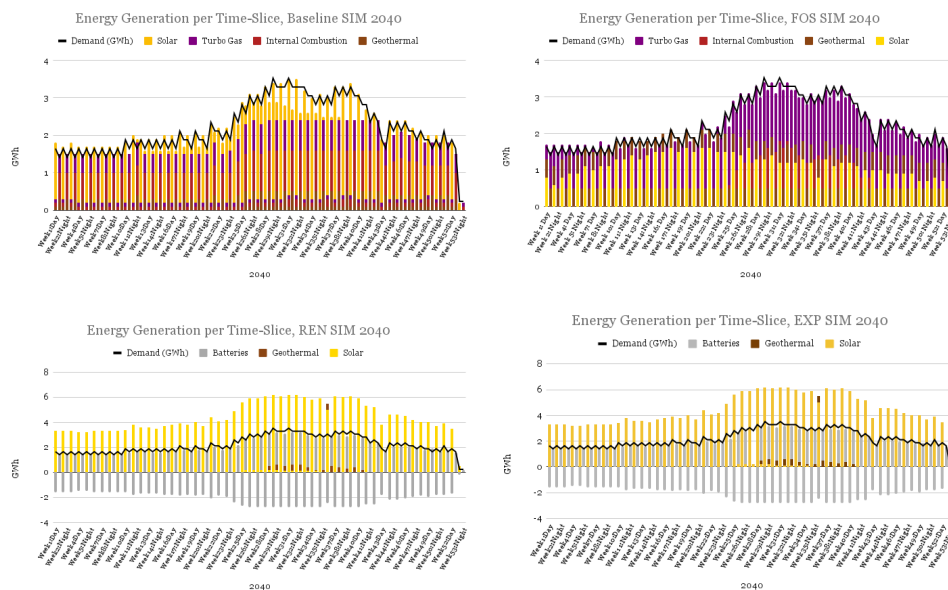


Figure 35: Energy Generation per Time Slice in 2040 in SIM for Baseline (u.right), FOS (u. right), REN (l.left) and EXP (l. right)

In the BAS scenario for 2040, the system relies primarily on solar power during the day, while at night, energy is mainly supplied by turbo gas, internal combustion, and geothermal power, with additional solar energy used during peak-demand months. This results in the annual average of renewable energy being 61.7%.

In the FOS scenario, most of the annual demand is met through solar and turbo gas generation and like before, during the energy-intensive summer months, the reliance on fossil-fuel plants increases to meet peak demand. The higher reliance on turbo gas in the scenario results in the annual average of renewable energy being 48.5%, which is the only time that the FOS scenario has a lower amount of renewables in the system compared to the Baseline.

In both the REN and EXP scenarios, total energy generation per time slice is nearly double that of the previous scenarios, primarily due to the incorporation of battery storage. Throughout most of the year, solar power and battery storage suffice to meet the energy needs, except during some summer months when geothermal energy is used to cover demand peaks caused by lower solar production.

5.3.3 Total Cost of Energy Production and Cost per Energy Produced

Below are the total system costs for different scenarios. A key observation is that the FOS scenario emerges as the most expensive option (alongside EXP until 2040), with the exception of the Baseline scenario.

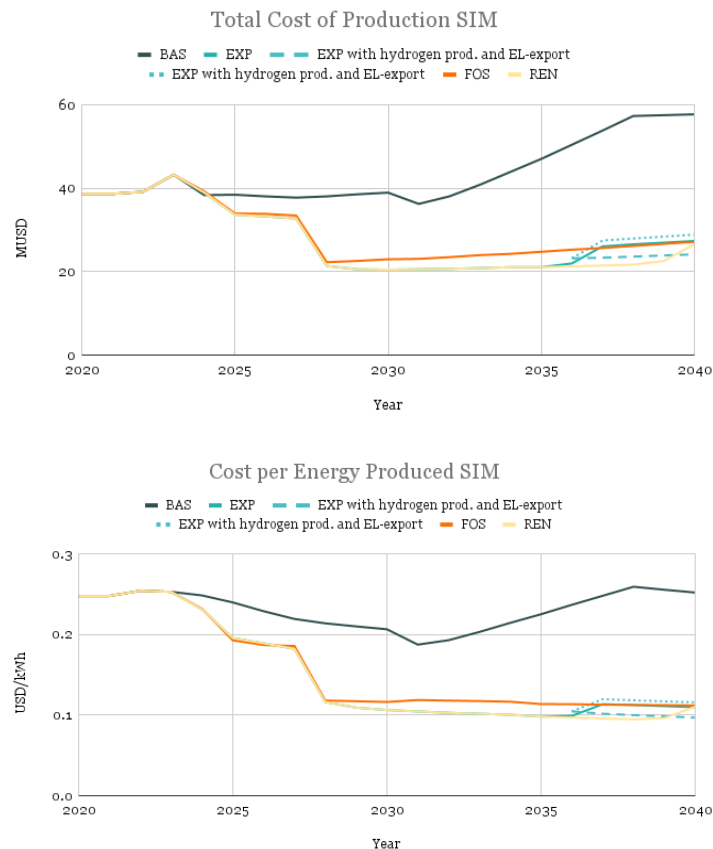


Figure 36: Annual cost of production for each scenario (upper) and Annual cost per energy produced (lower) from 2020 to 2040 in SIM

This is likely due to the system’s reliance on solar power, which is by far the cheapest energy source, as well as the high fuel costs—primarily from diesel and fuel oil—in the SIM scenario. Consequently, the REN scenario remains the most cost-effective option until 2040, when the inclusion of batteries slightly shifts the cost dynamics.

Regarding export options, once again exporting electricity is the most beneficial option compared to hydrogen production, which in SIM even increase the overall production costs. For EXP to be the most beneficial scenario in SIM, around 10% of the annual curtailed energy needs to be exported.

When comparing both the total cost of energy production and the cost per unit of energy produced, similar trends are observed. By 2040, in contrast to both SIBC and SIBCS, all three optimized scenarios have nearly identical costs. Since the installed capacity is much higher in the Baseline, the capital costs are mainly the reason behind the high cost of production.

5.3.4 Total Emissions from Energy Production and Emissions per Energy Produced

The differences in emissions, presented below, show that emissions in the BAS scenario increase through 2030, before gradually decreasing to a level below the 2023 value, decreasing by 25.9% (21.1 kTonnes CO₂-eq). In the FOS scenario, emissions decrease until 2028, after which they begin to rise again, reaching 79.8 kTonnes CO₂-eq in 2040, slightly lower than the 81.3 kTonnes CO₂-eq in 2023. In contrast, both zero-emission scenarios follow the same trajectory throughout the period, ultimately achieving zero emissions by 2040 and 2037, respectively. Similar to the cost trends, emissions per unit of energy produced exhibit comparable patterns across the scenarios.

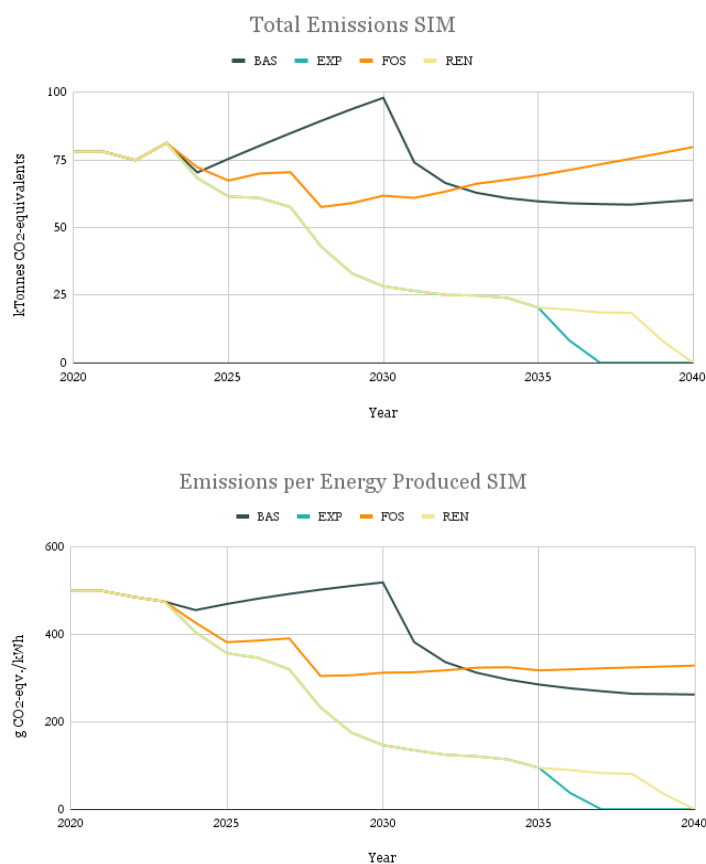


Figure 37: Emissions for each scenario (upper) and Emissions per Energy Produced in SIM from 2020 to 2040 (lower)

5.3.5 Annual and Weekly Curtailed Energy

The total curtailment in SIM differs significantly from the other regions, SIBC and SIBCS. Interestingly, in the BAS scenario, SIM experiences much higher levels of curtailed energy compared to the other regions, mainly due to the amount of installed capacity in BAS. However, it should be noted that both REN and EXP still experience high amounts of curtailed energy after 2035 compared to the total size of the system.

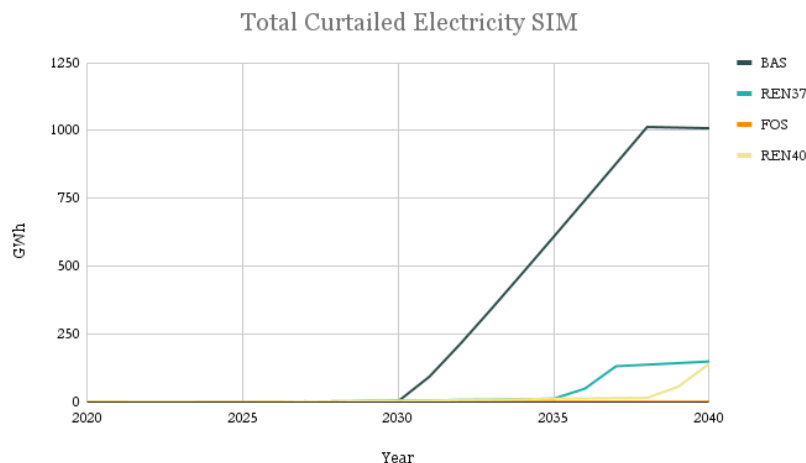


Figure 38: Total Curtailed Electricity 2020 to 2040 in SIM

The weekly curtailment 2040 shows similar trends as the previous areas, with the exception that all of the curtailment originates from solar power, as this is the only variable source in the system.

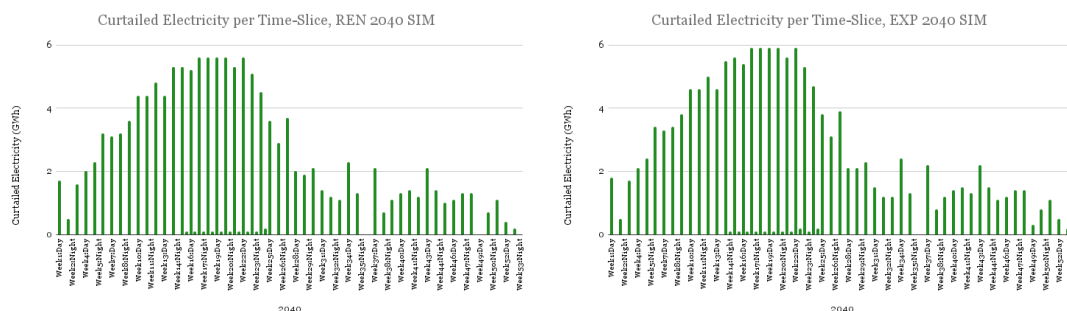


Figure 39: Total time-sliced Curtailed Electricity 2040 in SIM

5.4 Current and Future Challenges

The following sections present insights from interviews with key stakeholders in the energy sector, highlighting the perspectives and challenges faced by BC and BCS. These discussions provide inputs on the current state of the energy systems in both regions and the obstacles they encounter in transitioning to more sustainable energy solutions.

5.4.1 Baja California

The following information was obtained through interviews with representatives from the energy branch of the state secretary of economy (Secretaría de Economía e Innovación) in Tijuana, Baja California.

In BC there are several challenges regarding the current energy system. One issue has been that the total energy generation is lower than the demand, meaning import is crucial for the area in order to reduce the occurrence of blackouts. However, new projects from CFE are on the way and will start operation by 2026. Furthermore, there are several issues with the current grid. Many distribution lines are overloaded and are in need of expansion and many substations don't have enough capacity to transfer the amount of energy required. Both of these issues create several bottlenecks in the current energy system, increasing the difficulty of expansion and the introduction of renewable energy.

As mentioned in Section 4, the water supply is very energy intensive but also crucial for the social standard in large parts of the state of BC. The largest city of Tijuana does not have its own water supply and therefore, water is transported from Mexicali to Tijuana and the rest of the west coast are via a pipeline. However, Mexicali lies below sea level and, more importantly, at a lower elevation than Tijuana. As a result, water must be pumped uphill to reach Tijuana, a process that is highly energy-intensive and with the growing population of Tijuana, this energy demand is expected to increase.

A large expansion of renewable energy is affected by the mentioned issues. The importance of energy security is monumental, but since there is a deficiency in energy production, the CFE is mainly prioritizing fast and cheap energy sources, which are deemed to be internal combustion and combined cycle plants. The main reasoning for them being cheaper in the system today is due to the ability to build them close to already constructed transmission lines, which is the major cost barrier. However, it is not necessarily because they are cheaper, but rather because they are safer and faster to build. Additionally, these technologies do not suffer from intermittency in generation, allowing them to satisfy demand at any time.

Another obstacle is the areas in BC where the renewable potential is the highest are located in the south and middle of the state. However, there are two main issues to construct it there. Firstly, there are no already built transmission lines that can easily be connected to the energy plants. Secondly, the terrain there is quite rough, with a lot of mountains and hilly areas without easy accessibility to roads, making construction difficult. Furthermore, almost the whole southern part of the state is nature reserves and protected areas, resulting in difficulties obtaining permits.

Currently, there are no policies or legislative actions to increase the implementation of renewable energies in the energy system, neither on the state nor national level. However, there are some pushing for energy with lower carbon emissions. International companies in the state of Baja California are asking for cleaner energy for their local practices because of their attempts to decrease emissions in their supply chains. Previously, Baja California was cooperating more with the state of California than with the Mexican mainland, and the combination of the areas was seen as a mega-region called CaliBaja. However, with the changes in government in both countries, the relationship between Baja California and the Mexican federal government is expected to improve significantly, which could shift cooperation priorities. Additionally, with the new president elected in 2024, the national energy policies have undergone significant changes in favor of the energy transition. This means that the previous lack of national support for renewable energy may no longer apply under the current policies and goals..

5.4.2 Baja California Sur

The following information was gathered from an interview with Alfredo Sergio Bermúdez Contreras, Professor-Researcher in Renewable Energies at the Autonomous University of Baja California Sur (UABCS) in La Paz.

Similarly to BC, BCS faces significant challenges in its electricity system, amplified by its geographical isolation, which makes it an "electricity island" with limited flexibility. Seasonal variations in electricity demand follow a similar pattern to BC, with high peaks in summer and lower consumption in winter. Additionally, on shorter timescales, the lack of fast-response flexibility makes it difficult to stabilize fluctuations in the grid. Thus, despite growing interest in renewable energy, BCS remains heavily dependent on fossil fuels, raising concerns about the stability of its power system.

Integrating renewables into the grid presents major challenges, particularly due to transmission bottlenecks. Most electricity is generated in La Paz, while demand is concentrated in Los Cabos, pushing the grid to operate near its maximum capacity. Without investment in expanding transmission infrastructure or increasing local generation, these bottlenecks will likely worsen. The need for a more resilient grid is even more urgent given BCS's vulnerability to hurricanes, which have historically caused extensive damage and prolonged outages. While underground power lines could improve resilience, their high installation costs make them a difficult investment, especially in densely populated and expensive areas like Los Cabos (see Figure 4).

Despite these challenges, BCS, like BC, has strong potential for renewable energy. Solar power is widely viable, whereas wind energy, though beneficial, is more geographically constrained. Some of the most promising wind power sites, such as near Mulegé and the Pacific coast, lack sufficient grid connections and capacity, complicating their feasibility. There is ongoing discussion about integrating BCS's energy system with the rest of the country or the Baja California peninsula, but the future of such projects remains uncertain.

As BC, BCS has high emissions per kilowatt-hour compared to the rest of the country, making energy efficiency measures especially important. Improving building efficiency offers a significant opportunity, yet current building codes do not address energy considerations. This gap is important because air conditioning in poorly insulated buildings drives much of the region's electricity demand. Introducing energy-efficient building standards and encouraging behavioral changes through revised tariff structures could substantially reduce consumption.

Technological innovations will also be critical to managing the variability of renewable energy. New gas turbines offer faster response times than traditional thermal plants and could be paired with battery storage to handle fluctuations more effectively. Pumped hydro systems, particularly if integrated with desalination plants, hold great promise as well.

As with any major energy transition, there are risks and uncertainties involved. Weather-related risks, regulatory complexities, and environmental concerns all pose challenges. The permitting process for large-scale energy projects is often slow and must account for the region's protected areas and biodiversity. Long-term planning that balances environmental, technical, and economic objectives will be essential to mitigate these risks.

While the challenges in BCS are considerable, the region's relatively small size and isolation present an opportunity to pioneer innovative energy solutions. Lessons learned in BCS could serve as a model for other parts of Mexico, demonstrating how to achieve a resilient and sustainable energy system in a challenging environment.

5.5 Sensitivity Analysis

A sensitivity analysis has been conducted to assess the impact of variations in key input variables on the results. Three primary variables were altered or added during the analysis: **Social cost of carbon, the future demand growth** and **adding seasonal storage**. This approach allows for a deeper understanding of how sensitive the model is to changes in these parameters, providing insight into the robustness of the results under different assumptions.

5.5.1 Demand Growth

The demand growth data, presented in Table 1, was sourced from PRODESEN 2024-2038. Historically, actual demand growth has been lower than projected in these forecasts. Therefore, this assumption was incorporated into the sensitivity analysis to assess how variations in future demand growth might impact the modeling outcomes.

According to PRODESEN 2023-2037 (SENER n.dC), Mexico’s annual demand growth has historically averaged **2.5%** per year. This rate was applied to both SIBC and SIBCS to model a scenario with lower energy demand through 2040.

SIBC 2.5% Demand

Table 3 below shows how the change to 2.5% demand change valuable parameters in the scenarios FOS, REN and EXP.

Table 3: Key changes in 2.5% demand growth in SIBC

BC 2,5%	Change in Tot Production	Change in Solar Production	Change in Share of Solar	Change in Wind Production	Change in Share of Wind
FOS	-3.5 TWh	-15.5%	-3.6%	+10%	+25.7%
REN	-5.4 TWh	-26.3%	-11.1%	+1.1%	+22.1%
EXP	-3.2TWh	-17.2%	-7.1%	+9.2%	+22.4%

The reduction in solar power generation and simultaneous increase in wind power under the 2.5% demand growth scenario in SIBC reflect critical differences in how these technologies respond to lower energy demand. Solar power, being more dependent on daytime variability and requiring substantial land area, faces challenges in scaling effectively under slower demand growth. In contrast, wind power benefits from the ability to contribute to the grid during the night when the solar does not produce, especially during off-peak hours or seasonal demand fluctuations.

This shift also underscores the economic interplay between renewable resources: as demand growth slows, wind projects may achieve higher capacity utilization rates, making them more cost-competitive relative to solar.

The sensitivity cases are plotted against the original results below, revealing key variations in system performance.

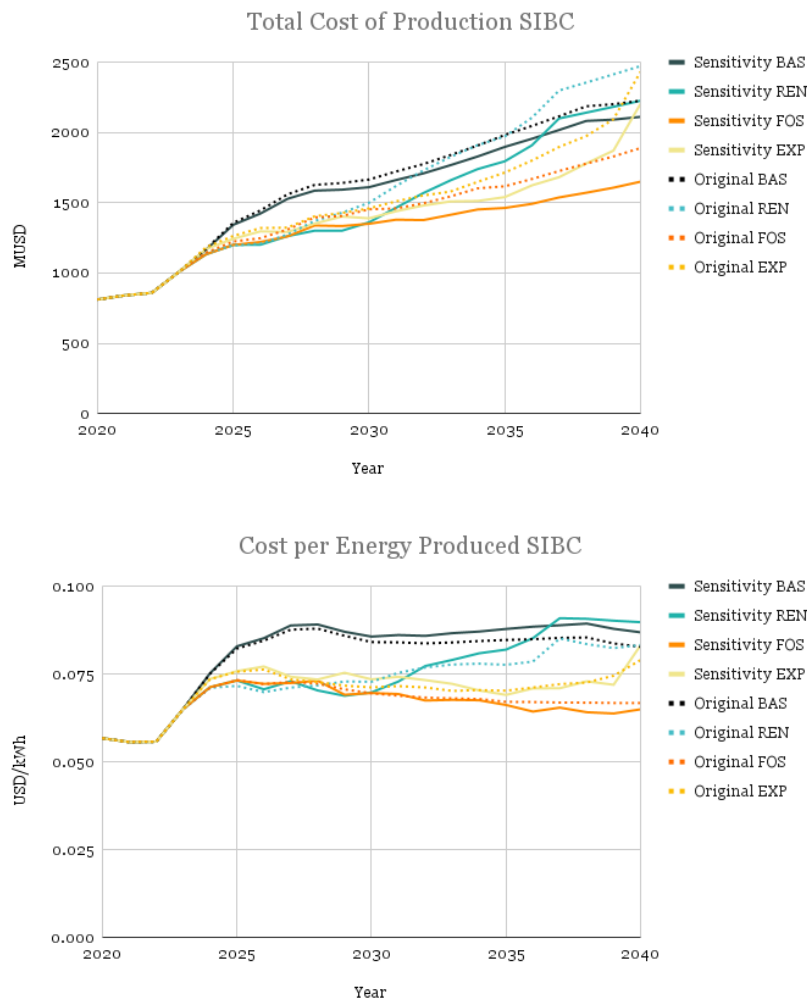


Figure 40: Annual Cost of Production (upper) and Cost per Energy Produced (lower) in sensitivity cases vs the original cases in SIBC

When examining the total cost of production, all sensitivity scenarios show lower costs compared to the original scenarios. The largest cost reduction is in FOS, due to lower fuel cost in the energy production. In the different scenarios, the total reduction in cost of production 2040 is 246.6 MUSD (-10.0%) in REN, 239.5 MUSD (-12.6%) in FOS, 228 MUSD (-9.4%) in EXP. Furthermore over the entire period from 2024 to 2040, the cumulative cost reductions are even more substantial: 2 300 MUSD in REN 2 000 MUSD in FOS and 1 800 MUSD in EXP.

When focusing on the cost per unit of energy produced, a slight variation appears: the sensitivity scenarios for BAS and EXP exhibit higher values than the originals. In the EXP scenario, this might be due to the higher share of wind power, which results in a higher capital cost per energy produced.

In terms of total emissions, the sensitivity cases exhibit slight differences in the patterns across scenarios. For the REN and EXP scenarios, total emissions are higher in the sensitivity case compared to the original, while for BAS and FOS scenarios, total emissions are lower in the sensitivity case. These differences emphasize how demand growth interacts with specific system configurations to influence emissions outcomes.

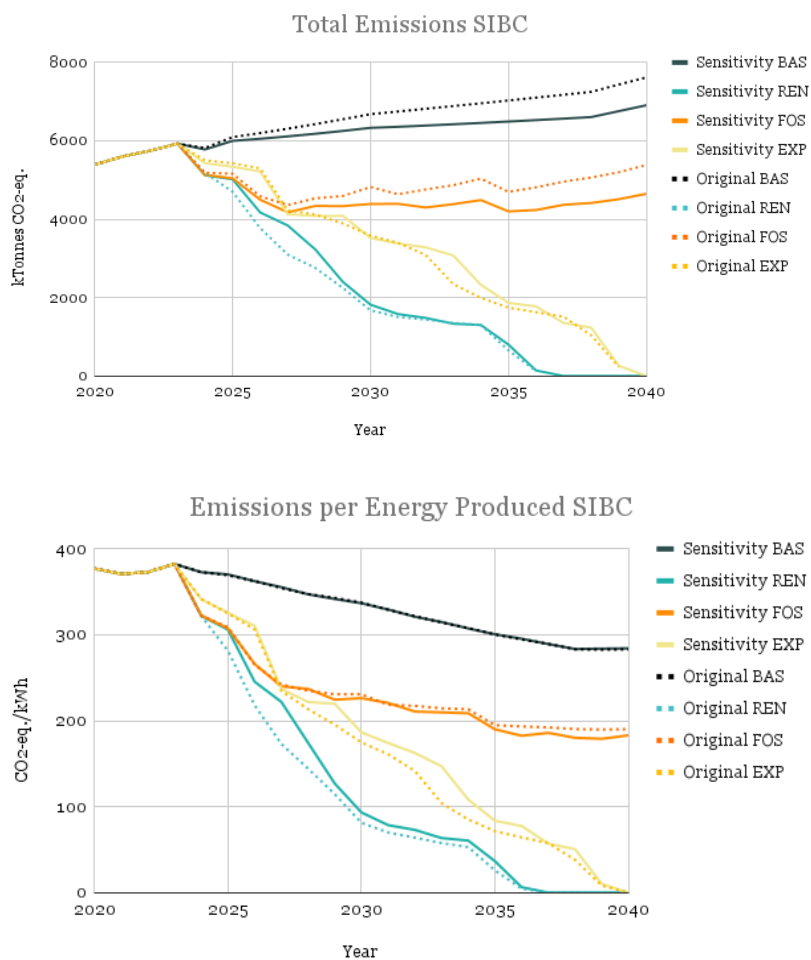


Figure 41: Annual Emissions (upper) and Emissions per Energy Produced (lower) in sensitivity cases vs the original cases in SIBC

SIBCS 2.5% Demand

Table 4: Key changes in 2,5% demand growth in SIBCS

BC 2,5%	Change in Tot Production	Change in Solar Production	Change in Share of Solar	Change in Wind Production	Change in Share of Wind
FOS	-906.8 GWh	-16.6%	-1.8 %	0%	+19.2%
REN	-1122.6 GWh	-13.7%	-1.0%	-25%	-14.3%
EXP	-938.8 GWh	-13.6%	-1.3%	-32.4%	-21.3%

The effect of reduced demand growth in SIBCS exhibits distinct trends compared to SIBC. Specifically, lower demand growth in SIBCS leads to a reduction in solar deployment, while wind power maintains or slightly increases its share. This difference highlights the varying resource dependencies and technological dynamics between the two regions and the amount of wind and solar resources.

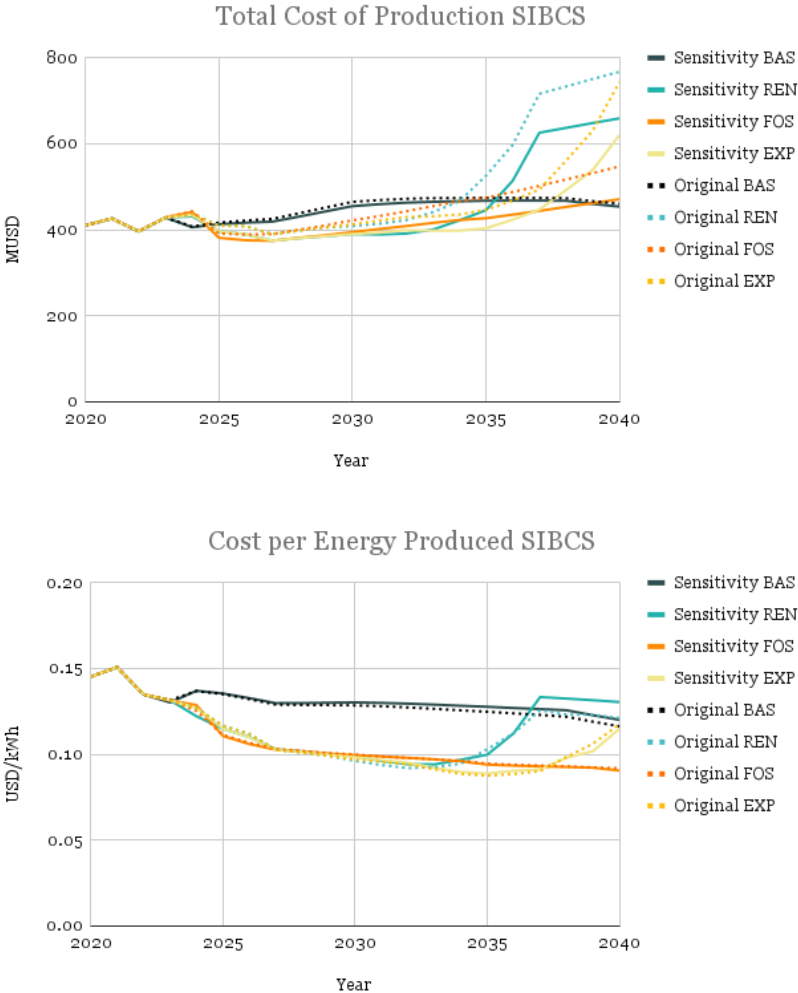


Figure 42: Annual Total Cost of Production (upper) and Cost per Energy Produced (lower) in sensitivity cases vs the original cases in SIBCS

In the 2.5% demand growth scenarios, the total system costs for the sensitivity cases in both SIBC and SIBCS are consistently lower than the original results across all scenarios (see figure above). This indicates that both regions experience economic benefits from a reduction in demand growth, highlighting the potential cost-saving advantages of lower electricity demand increases in isolated energy systems.

In the different scenarios the total reduction in cost of production 2040 is 109 MUSD (-14.1%) in REN, 76 MUSD (-13.9%) in FOS and 123 MUSD (-16.6%) in EXP. Furthermore over the entire period from 2024 to 2040, the cumulative cost reductions are even more substantial: 810 MUSD in REN 630 MUSD in FOS and 658 MUSD in EXP.

Compared with SIBC, the largest change in production cost is in the EXP scenario instead of FOS. This is most likely due to the decreasing of both wind and solar energy, resulting in lower capital costs all around. Furthermore, in EXP there is a large reduction of cost per energy produced, most likely due to similar reasons.

Looking at the emissions graphs in Figure 43, the trends in SIBCS follow the same patterns observed in SIBC.

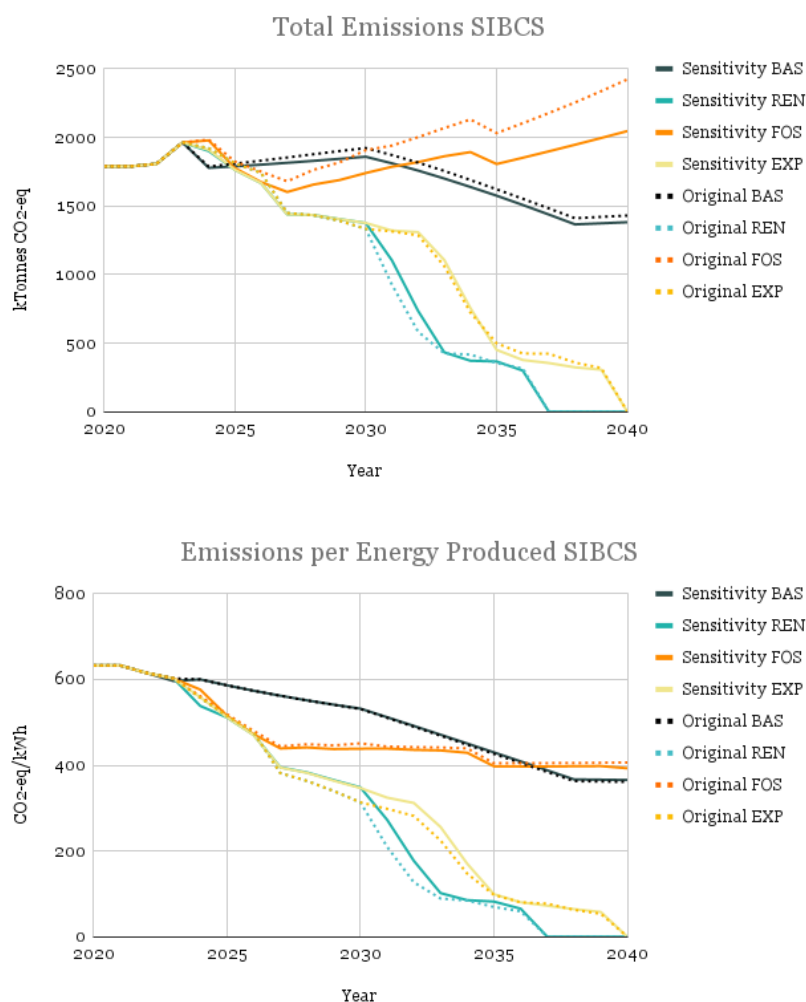


Figure 43: Annual Emissions (upper) and Emissions per Energy Produced (lower) in sensitivity cases vs the original cases in SIBCS

5.5.2 Social Cost of Carbon

The selected parameter for the SCC in this analysis is 50 USD per metric ton of CO₂, as outlined in Section 4.6. This value reflects a commonly used benchmark in policy and energy system modeling. SCC at 185 USD per metric ton CO₂ was used in this sensitivity analysis. Incorporating a higher SCC into the model would result in stronger economic incentives for renewable energy adoption, potentially accelerating decarbonization efforts. For example, increasing SCC could make investments in wind and solar more competitive relative to fossil fuels, even in scenarios with more moderate demand growth. Additionally, analyzing the cost of carbon at 0 USD per metric ton CO₂ would also provide useful insights into the potential impacts of different carbon pricing assumptions.

Below, is the difference in generation depending on the different SCC price in SIBC FOS scenario. As mentioned above, LEAP optimizes based on the lowest cost of production, and as can be seen, when SCC is low, the economic incentive to transition to renewable energy options is lower and therefore the expansion of wind and solar is slower.

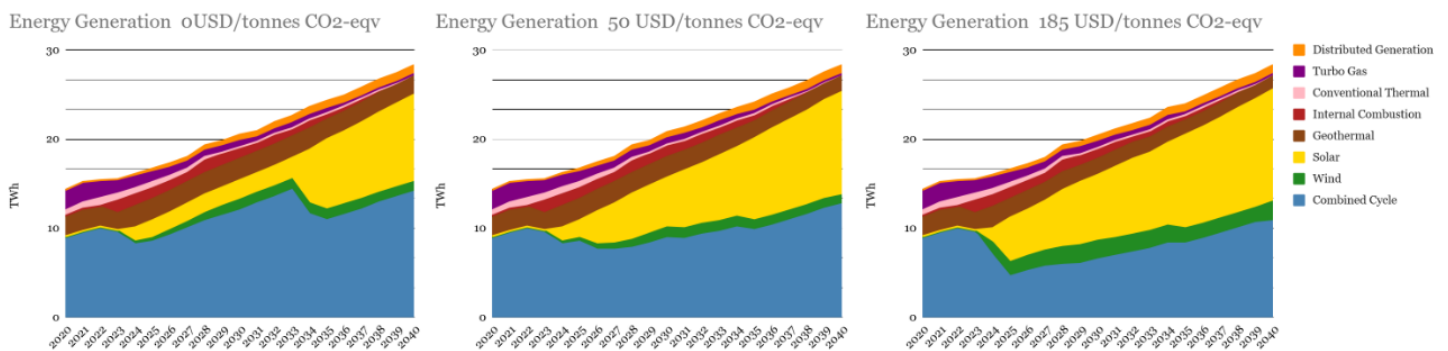


Figure 44: Difference in energy generation based on SCC values: 0, 50, and 180 (left to right).

Similarly, when SCC is high, the incentive to transition is much higher, resulting in a faster expansion in the figure to the left compared to the other two.

The sensitivity scenarios for SCC values of 0 and 185 USD per metric ton CO₂ are plotted below alongside the original results. As expected, an increase in the SCC results in higher total production costs, while a decrease leads to lower costs.

Focusing on costs in the year 2040, the REN and EXP scenarios show similar values, with earlier years following comparable trends. This is because the SCC of 185 USD per metric ton CO₂ increases costs more significantly when fossil-based production dominates the system. In contrast, the FOS scenario reveals an interesting outcome. By 2040, with an SCC of 185 USD per metric ton CO₂, the production cost is nearly identical to that of the EXP and REN scenarios. However, when the SCC is set to zero, the FOS scenario becomes the most cost-effective option overall.

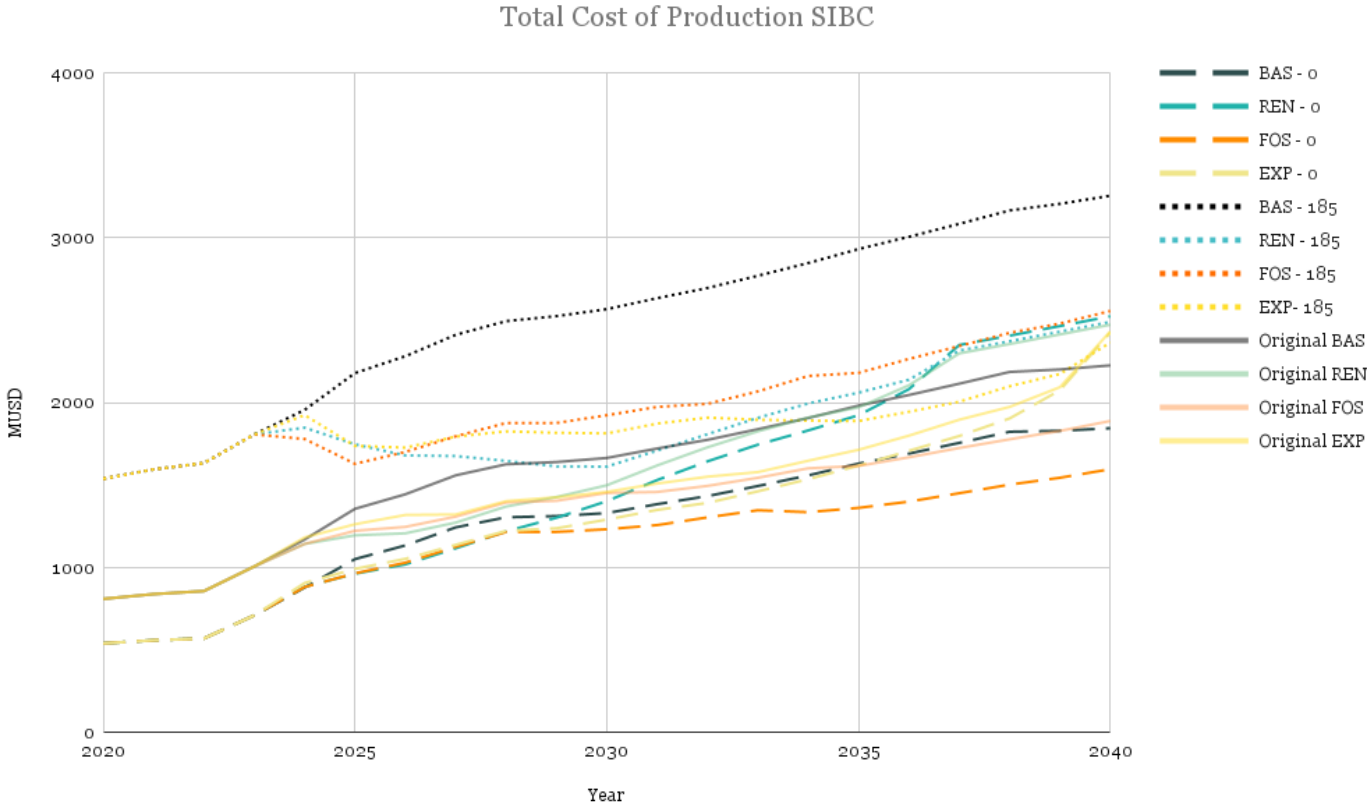


Figure 45: Total Cost of Production of the SCC sensitivity scenarios

However, when examining total emissions, the results show more variation. For the FOS scenario, the most noticeable difference occurs, with the SCC at 0 USD resulting in the highest emissions, followed by the original scenario, and then the 185 USD SCC. The largest difference is once again in the FOS scenario. The high SCC results in 15% lower emissions than the original FOS 2040, while the low SCC results in 11% higher emissions 2040.

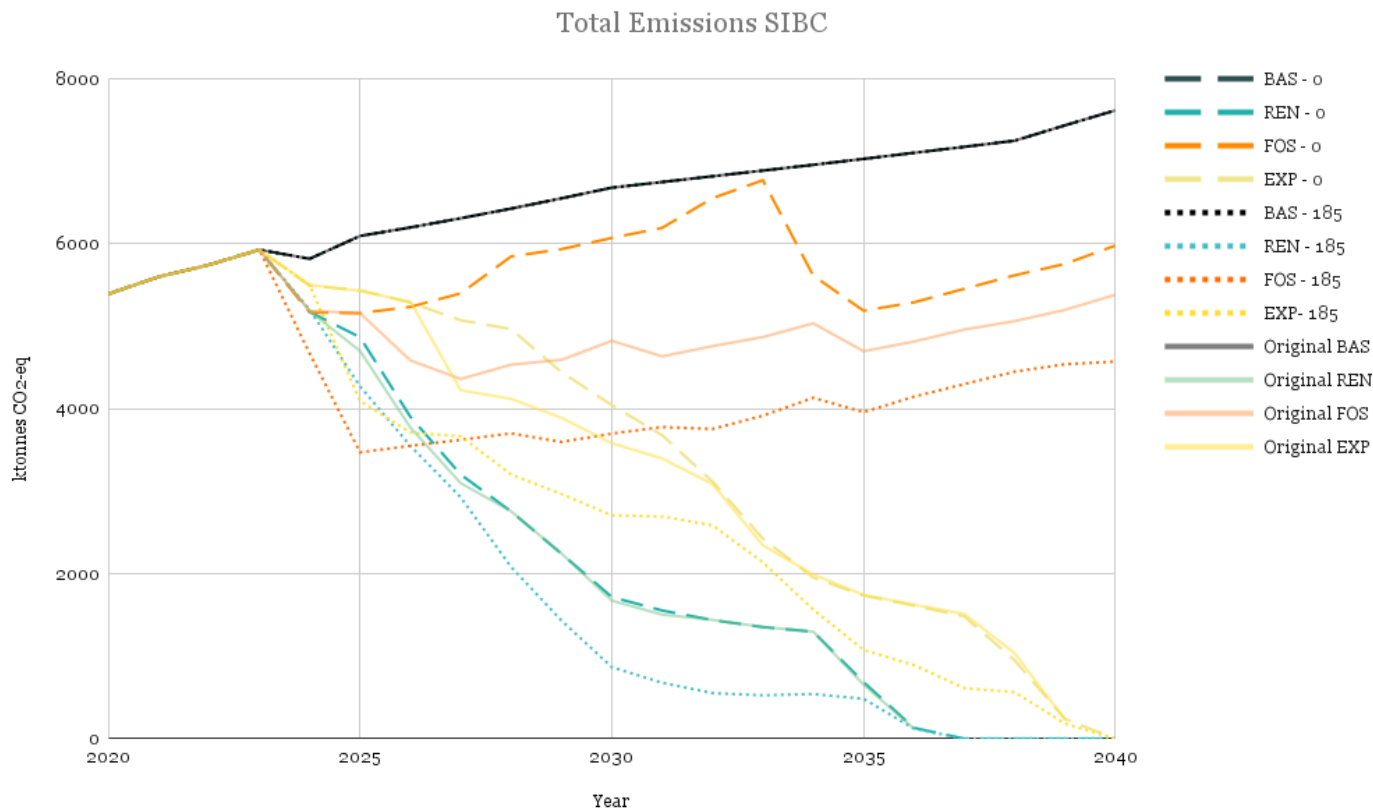


Figure 46: Total Emissions of the SCC sensitivity scenarios

This outcome is not surprising, as a higher SCC provides stronger incentives for the adoption of renewable energy, which typically leads to lower emissions.

The same patterns are observed in SIBCS and SIM, as shown in Appendix D.

5.5.3 Seasonal Storage

As mentioned in the methodology, the use of 4-hour batteries for energy storage offers both advantages and disadvantages. To address this, pumped hydro storage is introduced as a complementary storage solution with longer storage times, providing additional capacity to support energy demand during extended periods of low renewable production.

In both SIBC and SIBCS, the integration of pumped hydro storage with longer storage durations results in a significant reduction in total curtailed energy, as illustrated in Figure 47. This decrease underscores the vital role of long-duration storage in optimizing renewable energy utilization. By capturing excess renewable generation during periods of high output, pumped hydro storage reduces waste and enhances system efficiency.

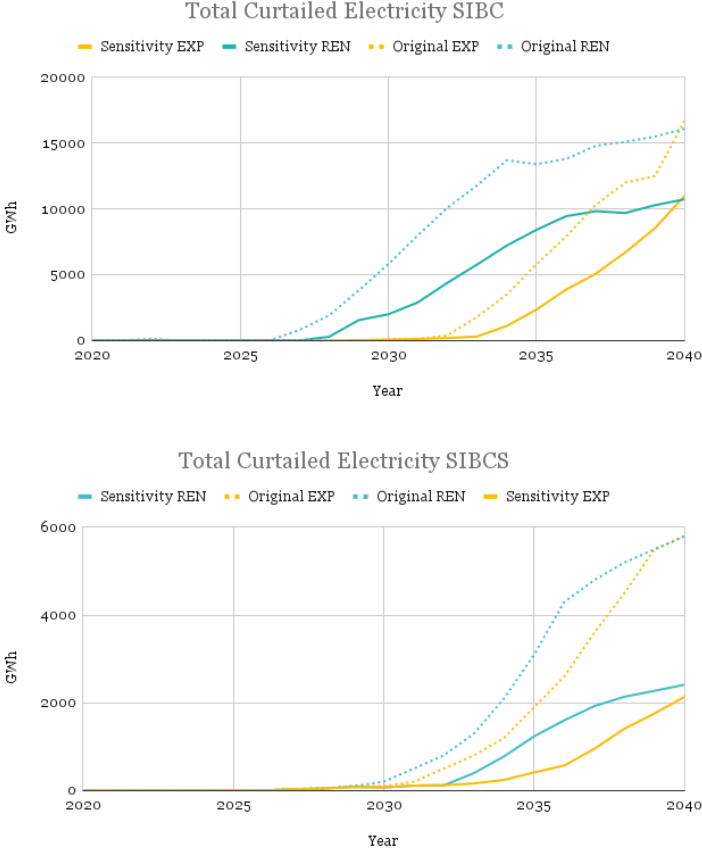


Figure 47: Total Curtailed Electricity in sensitivity cases vs original cases in SIBC (upper) and SIBCS (lower)

The reduction in curtailed energy not only improves the economic value of renewable generation but also lessens the need for backup fossil fuel generation, advancing decarbonization goals. The comparison between SIBC and SIBCS highlights that the benefits of pumped hydro storage are consistent across different system configurations, reinforcing its potential as an effective solution for managing seasonal mismatches between supply and demand.

Furthermore, the improved efficiency and flexibility offered by pumped hydro storage contribute to a reduction in total system costs, as shown in Figure 48. This efficiency mitigates the need for costly peaking power plants and additional infrastructure, providing a more cost-effective and sustainable pathway for regions with high renewable energy penetration.



Figure 48: Total Cost of Production in sensitivity cases vs original cases in SIBC (upper) and SIBCS (lower)

When utilizing PHS, the installed capacity decreases, as demonstrated in Table 5 and Table 6. This reduction occurs because PHS enables more long term energy storage and redistribution than only relying on battery storage, thereby reducing the need for additional installed capacity to meet peak demand. Consequently, the overall system costs decrease, as illustrated in Figure 33. The cost savings result from decreased dependence on renewable energy generation and the more costly battery storage to meet demand peaks and more effective load management, which optimizes the overall performance of the energy system. Additionally, the need for battery storage capacity also decreases.

Table 5: Installed Capacity 2040 in the original results vs sensitivity cases in SIBC (GW)

	Solar Result	Wind Result	Solar SA	Wind SA	Batteries Result	Batteries SA	PHS SA
REN	14.4	4.4	12.9	4.4	3.6	1	2.6
EXP	15.2	3.4	13.9	3.4	3.7	0.3	3.5

Table 6: Installed Capacity 2040 in the original results vs sensitivity cases in SIBCS (MW)

	Solar Result	Wind Result	Solar SA	Wind SA	Batteries Result	Batteries SA	PHS SA
REN	4660	950	3760	150	862	90	977
EXP	4510	1280	3850	150	871	90	925

6 Discussion

This section explores various pathways for the electrical system in the Baja California Peninsula, evaluating them in terms of emissions, production costs, and implementation speed. The feasibility of these pathways is analyzed concerning resource availability and existing policy frameworks. Key challenges, both current and future, are examined, with a focus on infrastructural, regulatory barriers and energy efficiency. Additionally, strategies to ensure energy security and grid stability, including the role of energy storage are discussed with the help of sensitivity analysis. Methodological limitations in assessing these pathways are also considered.

6.1 Comparative Analysis of Scenarios

The results presented in Section 5 demonstrate that implementing the proposed energy scenarios is technically feasible, given the assumptions made. The time-sliced generation analysis confirms that demand is met for all optimized scenarios during each time-slice, indicating system reliability under the modeled conditions.

There are several trends across all systems for the different scenarios regarding energy generation. First and foremost, the energy technology that increased the most in all scenarios and systems was solar power and it seems to be the most cost-effective way to produce energy in the peninsula. Especially in systems where energy storage is an option, the cheaper solar energy production is prioritized. The amount of wind seems to be in correlation to the availability of wind. In the SIBC, where the average availability over a year is higher, the share of wind power is around 20% in 2040 but in SIBCS and SIM it is around 7% or even non-present. This can surely be applied to other areas with high concentrations of incoming solar radiation, similar to the peninsula where the capacity factor is higher than the global average of 16.3% and the irradiance per square meter is high. Another benefit of solar energy is the speed at which it can be implemented. Once permits are obtained, it's a fairly easy process to assemble and install solar panels.

However, the expansion of solar energy in the renewable scenarios leads to a less diverse energy mix, heavily dependent on battery storage to meet nighttime demand, with minimal wind energy contribution. This reliance on batteries poses a potential energy security risk, as unfavorable solar conditions could occasionally limit energy production. In a system dominated by solar power, a substantial battery capacity is essential to ensure a stable electricity supply during periods of low generation from solar power. Furthermore, if all three systems were to connect in the future to optimize production, a diverse energy mix would likely be more advantageous than having similar energy profiles across all areas. It would be more efficient for SIBC to have a higher concentration of wind energy, given its favorable wind conditions, while high solar production could be prioritized in SIBCS and SIM, where solar potential is greater.

The emission trajectories in each scenario align with their respective objectives. In the Baseline scenario, emissions rise due to the continued reliance on fossil fuels, with minimal integration of renewable energy sources with the exception of SIM. Even though the FOS scenario continues with the expansion of fossil fuel technologies, it exhibits significant emission reductions, especially regarding emissions per energy produced, reflecting the increased penetration of renewables. The 100% Renewables with Storage and Export and Storage scenarios achieve zero emissions by 2037, as expected, due to their exclusive reliance on renewable energy and energy storage solutions.

Comparing the emissions with the current goal of renewable penetration, there are different level of success regarding the different scenarios and areas. In all areas, EXP and REN reaches over 45% of generation from renewable sources by 2030. Regarding FOS, it reaches over 45% in both SIBC and SIM but in SIBCS it only reaches 37%. Meanwhile, the BAS scenario—representing the current energy ministry plan—only achieves about 23% renewable generation across all regions by 2030, significantly below the 45% target.

Unsurprisingly, the highest total cost scenario is EXP and REN in most cases, except in SIM. The reason for this, mainly in SIBC and SIBCS, is that in order to implement a system with higher penetrations of renewables, more installed capacity is needed since wind and solar power have higher variability than traditional power plants. Furthermore, at the moment and in the future, costs for battery storage solutions are quite high, which drives up the costs of the systems. The relatively small difference in costs between the various scenarios in SIM is likely due, as mentioned earlier, to the higher fuel and O&M costs associated with fossil-based technologies. As shown in Figure 15, the fuel cost for diesel, the most commonly used fuel in energy production in SIM, is significantly higher compared to other fuels. This contributes to the higher overall production costs in the FOS scenario.

The role of fuel cost is further shown when comparing cost per energy produced between the different systems. In SIBC, where natural gas is used exclusively, the cost is much lower and introducing new renewable capacity increases the cost per energy produced. Comparing this to SIBCS and SIM where expensive diesel is used, introducing renewable capacity decreases the cost per energy produced. Especially in SIM, where it more than halves the cost per production. From this, the conclusion can be made that currently, natural gas is cheaper than adding renewable capacity. However, since renewable systems do not rely on imported fuels, they are less vulnerable to geopolitical fluctuations that could potentially drive up the cost of fuel imports.

In the EXP scenario, basic calculations were performed by integrating hydrogen production and the export of curtailed energy. As outlined in Section 4, a selling price of 32 USD/MWh for hydrogen was assumed, with California electricity prices serving as the basis for export income. The results for each system show that exporting even small amounts of curtailed energy is sufficient to make the export and storage scenario the most cost-effective among the three optimized scenarios. The key takeaway is that, in the long term, exporting electricity to the US is likely to be more advantageous than investing in green hydrogen production, provided that export prices remain stable. However, investing in hydrogen production is not entirely without merit, as it represents a relatively balanced investment and could stimulate economic growth. In the export calculations there are several uncertainties that are discussed in Section 6.4 below.

One way to lower the cost of renewable energy systems is through the implementation of long-term storage. As shown in the sensitivity analysis, this reduces overall system costs by maximizing the use of energy from variable sources, minimizing curtailment, and decreasing the need for additional installed capacity, thereby reducing high capital costs for new energy generation. Furthermore, as seen in Appendix A, the cost of (PHS) is significantly lower than that of battery storage.

6.2 Current and Future Challenges in the Electrical Systems of Baja California Peninsula

6.2.1 Transmission and Distribution Infrastructure

The transition to renewable energy in BC, BCS, and Mulegé faces significant challenges, primarily due to infrastructure and policy limitations. A major obstacle is the transmission network, where overloaded lines and substations create bottlenecks that hinder the integration of additional capacity. Addressing these issues requires not only immediate solutions but also a long-term strategy for grid modernization. Expanding and upgrading the transmission and distribution networks across the peninsula will be essential to manage the increased variability of renewable energy sources.

In BC, the areas with the highest renewable energy potential, such as sun-rich deserts, coastal zones, and mountainous regions suitable for wind power, are often located far from existing grid infrastructure. Extending the transmission network to these remote regions presents logistical challenges and high costs. Nevertheless, the abundance of solar resources throughout the states makes solar energy a highly promising option despite grid limitations.

In BCS, electricity demand is primarily driven by tourism rather than industrial activity. The region's rising energy needs prompt discussions about the economic and technical feasibility of connecting it to the national grid. Unlike industrial regions, where high electricity consumption correlates with economic output, the tourism sector may not justify the substantial costs required for new grid connections.

6.2.2 Policy and other Influences

To comply with the Electrical Industry Law where, as mentioned in Section 2, efficiency, quality, reliability, continuity and security of the electricity system must be ensured, current energy strategies in the region prioritize fast and easily deployable solutions, such as internal combustion and combined cycle plants. These technologies can be constructed close to existing infrastructure, reducing upfront costs but potentially prolonging dependence on fossil fuels which conflicts with decarbonization and sustainability. While batteries offer rapid deployment and high energy density, their high costs and limited lifecycle remain significant drawbacks. Conversely, PHS provides a cost-effective, long-term solution but requires suitable geographical conditions and higher initial investment, limiting its feasibility in certain regions.

Policy frameworks at both state and national levels offer limited incentives for renewable energy projects and impose weak restrictions on fossil fuel production. Current permitting processes are complex and time-intensive, discouraging private renewable energy developers from targeting the domestic market. Many instead focus on exporting energy to the United States, where the regulatory environment is often more favorable. As a result, investment in domestic renewable projects lags behind. In the southern regions of the peninsula, much of the land is designated as protected or reserved areas, making large-scale development even more difficult. Furthermore, in 2023 Mexico was ranked last of the Latin Countries regarding attractiveness for renewable investments (Ey 2023).

Non-domestic influences also shape the region's energy landscape. Large international companies operating in BC increasingly demand cleaner energy sources to align with global sustainability targets, further pressuring the region to modernize its energy system. Furthermore, BC's economic integration with the U.S. state of California creates potential opportunities for cross-border collaboration. California's ambitious decarbonization goals could incentivize BC to accelerate its renewable energy transition, especially if export of electricity to California from the whole system of BC would be a goal and not only from individual producers.

However, since both California and Baja California share similar climates, it is likely that California will also significantly expand its solar power capacity. This could result in both regions experiencing energy surpluses and deficits at the same time, complicating trade opportunities. As a result, Baja California may be incentivized to diversify its energy mix by increasing its share of wind power or investing in battery storage systems.

In contrast, in BCS, where international companies and industries are less prevalent, there is less pressure for expansion of renewable energy. However, since tourism is a major contributor to the economy, it might be in BCS's best interest to preserve the natural environment that attracts visitors, which necessitates a low environmental impact.

Who is paying for the consequences of climate change also plays a crucial role in the region's energy policy as shown in the sensitivity analysis. If decision makers sees the cost of climate change as someone else responsibility, SCC might not be taken into account. Calculating with a low SCC results in a slow transition to renewable energy being more profitable by reducing the competitiveness of wind and solar compared to fossil fuels. In contrast, if the view is that the cost of climate change is paid by the stakeholders in electricity generation, a higher SCC might be used. This makes acceleration of a transition more profitable, as shown in the SIBC FOS scenario where wind and solar deployment accelerates significantly. The total cost of production varies depending on the SCC value. By 2040, under a high SCC of \$185/ton CO₂, the production costs in the FOS scenario align more closely with those in the REN and EXP scenarios. However, with a zero SCC, the FOS scenario becomes the most cost-effective option overall.

CFE's role in this context is particularly interesting. As a government-owned company, it may have a vested interest in taking greater responsibility for reducing high emission electricity production. Climate change poses a direct risk to infrastructure and buildings, with the financial burden ultimately falling on the Mexican government. Consequently, CFE could be more directly impacted by the economic consequences of climate change, making it reasonable to consider a high SCC in its calculations.

6.2.3 Energy Efficiency Measures

In this study, energy efficiency measures have not been explicitly considered. However, when envisioning the development of future energy systems, it is important to acknowledge that reducing demand simplifies the integration of renewable energy and the overall system transformation. The most cost-effective and sustainable energy solution is to eliminate unnecessary consumption at its source.

For the three systems, which are all very energy intensive per capita compared to the rest of Mexico, energy efficiency offers a strategic and impactful pathway to overcome the logistical and financial challenges associated with the renewable energy transition. In both BC and BCS, energy efficiency is particularly relevant given overloaded transmission lines and substations. This complicates the challenges of meeting growing energy needs.

Energy efficiency holds potential to alleviate the bottlenecks in the current energy system. By reducing demand, the strain on overstressed transmission lines and substations can be lessened, creating more capacity for renewable energy integration. Managing energy demand peaks during the summer months is one of the peninsula's biggest energy challenges. Thus, reducing cooling demand, particularly during the hottest summer months, remains a key opportunity across both states. This can be achieved by improving building insulation and implementing energy-efficient cooling systems, which are especially relevant given that air conditioning in poorly insulated buildings drives a significant portion of electricity consumption. Updated building codes and targeted incentives for retrofits could play a transformative role in aligning infrastructure with sustainability goals.

As seen in the sensitivity analysis, a slightly lower annual demand increase, 2.5% instead of 3.3% in SIBC or 3.5% in SIBCS, can lead to significant cost savings. These savings could either be preserved or reinvested in long-term energy efficiency measures, which would further reduce total emissions from the energy system, even if fossil fuels continue to be part of the energy mix. If future electricity demand growth is less than projected, it could significantly affect economic and environmental planning. Reduced demand growth would likely lower the pressure to expand generation capacity, decreasing the need for large-scale infrastructure investments and reducing system costs overall. However, the higher cost per unit of energy under the EXP scenario may indicate challenges in optimizing renewable energy integration at smaller scales or with reduced demand. This highlights the importance of considering system-level trade-offs in achieving emission reduction targets and aligning with decarbonization goals.

Additionally, in BC, water pumping accounts for a significant share of electricity consumption. Implementing more efficient pumping technologies, optimizing operations, and redesigning energy-intensive systems in Tijuana's water supply network could lead to substantial energy savings. These improvements would not only reduce energy demand but also lower operational costs and enhance the sustainability of essential services. Integrating water pumping with a PHS system could offer further benefits. By transporting and storing larger volumes of water in Tijuana during periods of energy overproduction, the system could help balance supply and demand. Additionally, if storage facilities are constructed at a high enough elevation, they could also generate electricity when needed, further contributing to grid stability.

Energy efficiency directly addresses the root causes of high energy demand, creating a cascading effect throughout the energy system: lowering peak loads, reducing emissions, and supporting progress toward climate goals.

6.3 Feasibility in Regards to Renewable Sources

As previously mentioned, the Baja California Peninsula has abundant renewable energy resources, particularly solar power. However, across various scenarios, significant amounts of both solar and wind energy are required to meet future demand. The following section analyzes the results, assesses feasibility, and puts them into perspective. Since the installed capacity of SIM in 2040 is quite small compared to the other areas, it is assumed to be feasible.

To estimate the land area required for solar and wind energy under different scenarios, calculations were based on data from existing large-scale energy plants. For solar power, the Xinjiang Solar Plant in China was used as a reference. This plant has an installed capacity of 3.5 GW and covers 33 000 acres, with an average global horizontal irradiance (GHI) of 4 kWh/m² (Howe 2024). For wind power, the Los Vientos I Wind Farm in Texas was used, with an installed capacity of 200 MW over 30 000 acres and an average wind speed of approximately 8 m/s (Power Technology 2016).

In Baja California, the analysis focused on the northern region, where most current energy infrastructure is located. The designated study area covers approximately 5 500 km², with distances to transmission lines ranging from 30 to 50 km. The region's average GHI is 5.9 kWh/m²/day, higher than in Xinjiang, suggesting a lower land requirement per installed solar capacity. However, the average wind speed is 5.8 m/s, lower than at Los Vientos, meaning a larger land area is needed for wind power generation.

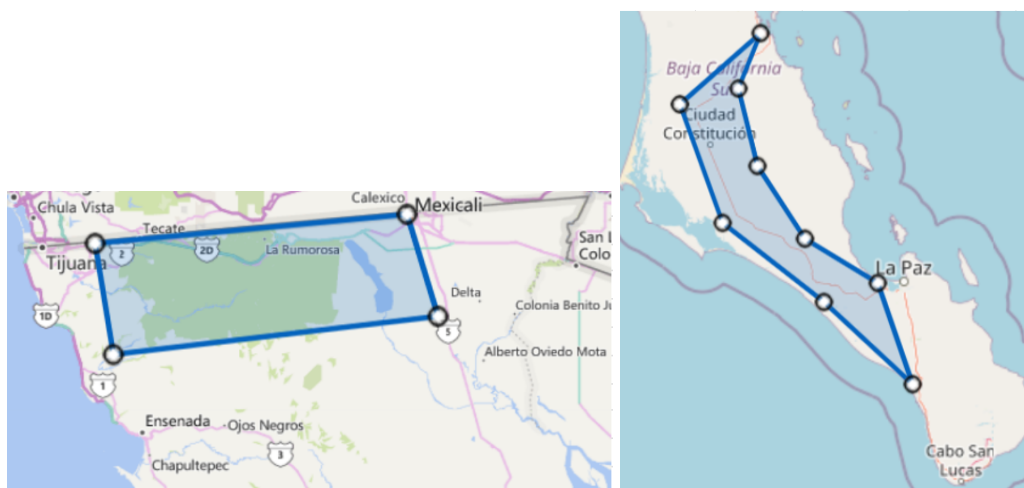


Figure 49: Area where renewable energy is suited in regards to current infrastructure. Maps from BingMaps using CalcMaps to calculate

In Baja California Sur, areas surrounding existing infrastructure, primarily near roads, were also examined. The study area spans approximately 8 500 km², with similar distances (30–50 km) to transmission lines. The average GHI is slightly higher than in Baja California, at 6.2 kWh/m²/day, but the average wind speed is lower at 5.2 m/s.

The table below presents the estimated land requirements for solar and wind power under different scenarios:

Table 7: *Production of each Renewable Source and calculated area needed in 2040*

	BC Prod. Solar	BC Area Solar	BC Prod. Wind	BCS Area Wind	BCS Prod. Solar	BCS Area Solar	BCS Prod. Wind	BCS Area Wind
FOS	11.6 TWh	170 km ²	1.0 TWh	1500 km ²	2.3 TWh	30 km ²	157 GWh	350 km ²
REN	20.5 TWh	300 km ²	9.2 TWh	6700 km ²	5.5 TWh	80 km ²	510 GWh	1100 km ²
EXP	22.1 TWh	330 km ²	6.5 TWh	5200 km ²	5.8 TWh	80 km ²	473 GWh	1000 km ²

In northern Baja California, solar resources are sufficient to meet the projected 2040 demand across all scenarios. However, wind energy integration is more complex. In the FOS scenario, existing infrastructure can support both wind and solar development. The area needed for the total wind production in REN exceeds the area marked in the map, meaning that in that scenario, the expansion of the infrastructure is more pressing than in FOS, which is not surprising.

In the EXP scenarios, land availability is barely enough to accommodate both wind and solar, although spatial constraints may pose challenges. Since solar panels are sensitive to shading, co-locating wind and solar farms in close proximity may not be ideal. Additionally, as highlighted in the background, agricultural activities in the designated area further intensify land-use competition.

In Baja California Sur, both solar and wind resources are abundant. However, as emphasized in interviews, wind projects must be strategically planned to maximize efficiency, as optimal wind conditions are highly site-specific. In contrast, solar power potential is consistently high across the state, making it easier to deploy.

Regarding the speed of implementation for the different scenarios, significant challenges exist for the renewable scenarios. As noted earlier, transmission lines in Baja California are crucial for the necessary expansion of solar and wind energy to achieve a 100% renewable system. The required infrastructure development could be perceived as an insurmountable obstacle, potentially redirecting investments toward fossil fuel-based production. This delay in initiating the necessary renewable investments could hinder the transition to a renewable energy system. In contrast, Baja California Sur benefits from the location of transmission lines that allow for more renewable energy to be developed around the existing infrastructure, making the renewable scenario more feasible in this region.

As mentioned, the permitting process for new electricity generation remains a significant obstacle. Solar power requires less land per unit of energy produced compared to wind, as previously discussed. This advantage may favor systems with a high concentration of solar power, particularly in SIBCS and SIM, since the reduced land requirement could lead to a shorter permitting process, streamlining development and benefiting all stakeholders.

At the end, it all comes down to the policy decisions. Without a major push from policy makers and major stakeholders, the likelihood of either of the scenarios is quite low. As mentioned above, the investments needed and the improvement of permits are essential for a system with more renewable energy, and without a strong stance on climate action, it is less likely that it will happen. Maintaining energy security while transitioning to renewables will also require robust policies that incentivize investments in grid modernization and storage infrastructure, ensuring that reliability is not compromised.

6.4 Uncertainties

Accurately estimating technology costs is a critical factor in energy system modeling, yet significant uncertainties remain. Cost projections vary widely between sources, which can influence the outcomes of this study. While most cost estimates were sourced from INECC, comparisons with other datasets, such as those from NREL, reveal significant discrepancies (see Appendix D). In some cases, these differences are substantial enough to impact the overall findings. For instance, NREL's estimated capital cost for geothermal is 246–325% higher than INECC's, and the variable O&M costs for Combined Cycle and Turbo Gas may be underestimated in this study. While regional factors, such as Mexico's geothermal resource availability, could explain some of these differences, they highlight the challenge of applying a single cost assumption to an entire system. If the findings are to be relevant beyond Baja California, revisiting and validating these cost estimates is essential.

Furthermore, a major concern is the cost trajectory of battery storage systems. When modeling, future cost reductions in renewable energy technologies have been assumed and if anticipated cost reductions do not materialize, the REN scenario could become less economically attractive, potentially reinforcing reliance on fossil fuel-based reserves.

A related issue is the treatment of renewable energy variability. The study assumes that wind and solar generation in 2023 remains constant in future years, despite the fact that renewable energy production is subject to significant fluctuations. This assumption could lead to an overestimation of available energy, affecting system reliability. Even though a reserve margin of 20–30% is included in the scenarios, variations in actual energy production could still pose risks to energy security.

Uncertainty also surrounds the potential for energy exports, particularly in relation to green hydrogen. As an emerging technology, green hydrogen production costs vary widely depending on location and energy input costs. This study relies on a single data source, but actual costs in Baja California could differ significantly. Additionally, the assumption that electricity and hydrogen selling prices remain constant over time does not reflect market realities. California's electricity prices are expected to fluctuate due to evolving environmental policies, including efforts to expand affordable solar power while integrating costly battery systems. Similarly, hydrogen prices will depend on global market developments, which remain highly uncertain.

In our analysis, we obtained unexpectedly low CF for wind power, ranging between 15-24%, which are significantly lower than the solar CF in the region (26%) (see Appendix A). This is uncommon, as wind power typically exhibits a higher CF than solar in many locations. One key assumption affecting this result is the rated wind speed of 14 m/s. If this value does not accurately reflect the wind resource characteristics in the region, it could lead to an underestimation of wind energy potential. Additionally, uncertainties in the wind speed data, spatial and temporal resolution of the dataset, and potential modeling limitations could contribute to this discrepancy. A more detailed validation of wind resource data, as well as sensitivity analyses on key parameters such as cut-in, rated, and cut-out wind speeds, could help refine these estimates.

6.5 Methodology

There are several aspects of the methodology that could be adjusted to improve the reliability of the results. For instance, the accuracy of the models heavily depends on the quantity and quality of the data provided. In some cases, specific data, such as hourly production details for each energy process, were unavailable, requiring assumptions to fill those gaps. If such detailed data were available, it would likely lead to more accurate and reliable model outputs.

Additionally, incorporating information about the expected decommissioning timelines of existing power plants, as well as the salvage values of the technologies, would result in outcomes that are more closely aligned with real-world conditions. This would provide a more realistic basis for planning and decision-making by ensuring the models account for the full life cycle of energy assets and their residual value.

Another limitation stems from the simplifications required in modeling complex energy systems. LEAP, as a modeling tool, is designed to handle large datasets and test various scenarios, but it inevitably generalizes or omits certain system dynamics. Inputs such as technology costs, demand patterns, and resource availability rely on projections that carry inherent uncertainties. While these approximations make the model more practical, they also contribute to uncertainty in the results.

7 Conclusion

The transition to a sustainable and resilient energy system in the Baja California peninsula is both an urgent challenge and a significant opportunity. This study has highlighted the technical pathways and policy measures required to achieve low emissions. In the results from the modeling, solar power proved to be the most cost-effective source of energy for the peninsula, particularly when energy storage systems were utilized. This led to a reliance on stored solar energy to meet nighttime demand, resulting in a less diversified energy mix. At the same time, the results indicated that a 100% renewable solution, including energy storage, is feasible though at a higher cost mainly due to the need for increased installed capacity and battery storage.

Successfully implementing this transition depends on addressing three key challenges: modernizing and expanding the transmission network, streamlining regulations and permitting processes, and developing large-scale energy storage to ensure grid stability. While storage solutions help integrate renewables, they come with high investment costs and infrastructure demands.

Achieving a sustainable transition requires strategic investments, policy reforms, and coordinated planning. Strengthening grid infrastructure, enforcing emissions standards, and providing incentives for renewables will be key to success. By addressing these challenges while prioritizing energy efficiency, the Baja California Peninsula can build a resilient energy system that balances economic growth, environmental protection and social equity.

Achieving net-zero emissions is not just a technical or policy challenge, it is a societal one. A sustainable energy future for the Baja California peninsula will require balancing economic growth, environmental protection and social equity. While this study outlines the pathways to decarbonization, the success of these strategies will ultimately depend on sustained political will, public-private collaboration and the ability to engage communities in the transition process. By addressing these uncertainties and risks while prioritizing energy efficiency, the region can achieve a resilient, low-carbon energy system.

8 Future research

For future studies, it would be valuable to consider extending the timeline for achieving renewable energy targets beyond 2040. Adjusting the timeline could allow for more realistic milestones that take into account the specific regional challenges in developing renewable infrastructure, as well as alignment with national energy policy goals. This approach could provide a more feasible path towards sustainable energy transitions within the unique context of Baja California and Baja California Sur.

Additionally, incorporating future transmission lines between the systems into the model could significantly impact the results. In reality, even if it may take some time, adding transmission lines to and from the peninsula is both reasonable and expected. However, due to the lack of clear future plans and the complexity of modeling transmission lines in LEAP, this factor was not included in the analysis.

Exploring the potential role of green hydrogen more in depth as an energy carrier could also be a valuable area for future research. Hydrogen produced from renewable energy sources might serve as a way to store excess energy or as an exportable energy product, complementing renewable generation during periods of low output.

Offshore wind energy is another promising area of study. Given the peninsula's proximity to the Pacific Ocean, investigating the feasibility and potential benefits of offshore wind installations could open up new opportunities for diversifying the energy mix and achieving greater energy independence. Such development could also complement existing renewable resources while minimizing the impact on protected natural areas in the region.

Finally, future studies could benefit from conducting more specific case studies on renewable energy projects in the region. This could include detailed assessments of local solar farms, wind farms, or pumped hydro locations to provide a deeper understanding of the practical challenges and successes of renewable energy deployment.

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10 Appendix

10.1 Appendix A: Initial Data

10.1.1 Installed Capacity 2020-2023 and the predicted Installed Capacity 2030 and 2038, data from PRODESEN, 2021-2035, 202-2036, 2023-2037, 2024-2038

Table 8: *The Installed capacity in SIBC [MW]*

Type of Technology	2020	2021	2022	2023	2030	2038
Combined Cycle	1821	1821	1821	1821	3370	3370
Internal Combustion	17	17	17	17 (429 MW Testing)	642	642
Wind Power	40	40	40	40	564	3387
PV-Solar	47	51	51	51	1243	1243
Geothermal	570	570	570	570	570	570
Conventional Thermoelectric	320	320	320	320	320	320
Turbogas	434	459	459	459	459	459
Batteries					180	265
SUM	3249	3278	3278	3278	7348	10256

Table 9: *The Installed capacity in SIBCS [MW]*

Type of Technology	2020	2021	2022	2023	2030	2038
Internal Combustion	343	343	343	352	352	207
Wind Power			50	50	50	50
PV-Solar	56	79	99	99	360	482
Conventional Thermoelectric	113	113	113	113	113	0
Turbogas	315	470	506	606	676	676
Batteries					269	787
Nuclear						100
SUM	837	1015	1121	1230	1820	2509

Table 10: *The Installed capacity in SIM [MW]*

Type of Technology	2020	2021	2022	2023	2030	2038
Internal Combustion	65	65	65	65	65	65
PV-Solar	1	1	1	1	4	499
Geothermal	10	10	10	10	10	10
Turbogas	14	14	14	14	80	80
SUM	90	90	90	90	159	654

10.1.2 Energy Production 2021-2023, data from PRODESEN, 2021-2035, 202-2036, 2023-2037, 2024-2038

Table 11: Energy Production in SIBC [GWh]

Type of Technology	2021	2022	2023
Combined Cycle	9460	10034	9568
Internal Combustion	120	116	1367
Wind Power	107	52	99
PV-Solar	126	127	121
Geothermal	2360	2211	1913
Conventional Thermoelectric	675	903	840
Turbogas	2196	1790	1403
SUM	15044	15233	15311

Table 12: Energy Production in SIBCS [GWh]

Type of Technology	2021	2022	2023
Internal Combustion	1318	994	1112
Wind Power		93	141
PV-Solar	193	218	263
Conventional Thermoelectric	538	543	510
Turbogas	777	1091	1231
SUM	2826	2939	3257

Table 13: Energy Production in SIM [GWh]

Type of Technology	2021	2022	2023
Internal Combustion	93	96	109
PV-Solar	2	1	1
Geothermal	37	40	47
Turbogas	24	17	14
SUM	156	154	171

10.1.3 Fuel Costs, data from PAMRNT 2024-2038

Table 14: Costs for different fuels for electricity production

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Natural Gas	3.43	4.10	4.48	5.09	5.24	4.90	4.67	4.64	4.57	4.61	4.68	4.81	4.85	4.93	5.03	
Fuel Oil BCS	11.26	10.60	9.76	8.82	8.69	8.65	8.62	8.60	8.59	8.54	8.50	8.54	8.56	8.69	8.88	
Diesel	31.44	31.06	29.98	28.87	28.61	28.46	28.32	28.15	27.97	27.82	27.56	27.48	27.40	27.42	27.52	
Uranium	0.77	0.77	0.78	0.79	0.8	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.89	0.9	

10.1.4 Cost of different technologies 2023 and future predictions, data from INECC and NREL(Batteries, PHS)

Table 15: *Economical information of the different technologies (from 2018)*

Technology	Lifetime [Years]	Capital Cost [USD/kW]	Fixed O&M Costs [USD/kW/year]	Variable O&M Costs [USD/MWh]
Combined Cycle	30	1023	19.18	3.33
Wind Energy	25	3175	38.47	0
Solar Energy	27	1400	10.8	0
Geothermal	30	1908	106.12	0.1
Internal Combustion	25	2905	94.61	5.25
Conventional Thermal	30	2065	36.15	3.03
Turbo Gas	30	921	5.15	4.85
Batteries (NREL 2024d)	15	2080	47.6	0
Pumped Hydro Storage (NREL 2024c)	30	1020	5.1	0.242
Nuclear Energy	60	4027	102.08	2.42

Table 16: *Change in cost of added technologies in the models until 2040*

Technology	Change in Capital Cost	Change in Fixed O&M Costs	Change in Variable O&M Costs	Source
Combined Cycle	-12.2% by 2040	-12.5% by 2040	-10.3% by 2040	NREL 2024a
Wind Energy	-12.3% by 2025, -9.7% by 2040	-15% by 2040	-	NREL 2024b
Solar Energy	-44% by 2035, -1.3% anually until 2040	-32.4% by 2035, -3.6% by 2040	-	NREL 2024e
Internal Combustion	-13.7% by 2040	-10% by 2040	-	NREL 2024a
Turbo Gas	-13.7% by 2040	-10% by 2040	-	NREL 2024a
Batteries	-17.7% by 2025, - 39.5% 2040	-18.7% by 2025, -42.1% by 2040	-	NREL 2024d
Pumped Hydro Storage	-	-	-	NREL 2024c

10.1.5 Efficiencies and Maximum Availability

Technology	Efficiency	Source
Combined Cycle	48%	Oh, et.al 2021
Wind Energy	30%	EPA 2013
Solar Energy	27%	Green, et. al. 2022
Geothermal	26% SIBC, 12% SIM	Sadiq 2014
Internal Combustion	40%	CENACE n.d.A
Conventional Thermal	37%	IEA 2014
Turbo Gas	36%	CENACE n.d.A
Batteries	85%	NREL 2024d
Pumped Hydro Storage	80%	NREL 2024c
Nuclear Energy	36%	Marques et.al. 2019

10.1.6 Cost of Hydrogen Production

Table 17: Parameters of Hydrogen Production from LAZARD

Category	1 MW	20 MW	100MW
Capital Costs	2 300 000 USD/MW	1 560 000 USD/MW	1 235 000 USD/MW
Fixed O&M (1.5% of Capital Cost)	34 500 USD/MW	23 400 USD/MW	18 525 USD/MW
Lifetime	20 years	20 years	20 years
Availability	34% *	34% *	34% *
Efficiency	58%	58%	58%
Annual Prod.	149 MT	2 988 MT	14 939 MT

10.1.7 Wind and Solar Availability

To determine availability, wind and solar data from NREL was used. The year and coordinates for each data set are described in the table below.

Table 18: Year and coordinates for the different data-sets

Resource	Year	Area	Longitude	Latitude
Wind		SIBC	-115.58	31.45
	2020	SIBCS	-110.77	24.52
		SIM	-112.9	27.28
Sun		SIBC	-115.5	31.29
	2022	SIBCS	-111.34	25.33
		SIM	-112.9	27.28

The hourly data sets were developed into an hourly availability by dividing the energy in the wind speed or the global horizontal irradiance with the rated energy for either wind or solar. For wind, the cut-in speed was assumed to be 3m/s, cut-out 25 m/s and rated energy at 14 m/s. The basic calculation for the availability for wind was:

$$Availability(\%) = 100 * Windspeed^3 / ratedWindspeed^3 \quad (1)$$

For the solar energy, the assumed rated energy of a solar panel was 1000W/m², which resulted in the equation:

$$Availability(\%) = 100 * GHI / 1000 \quad (2)$$

The results are shown in the figures below.

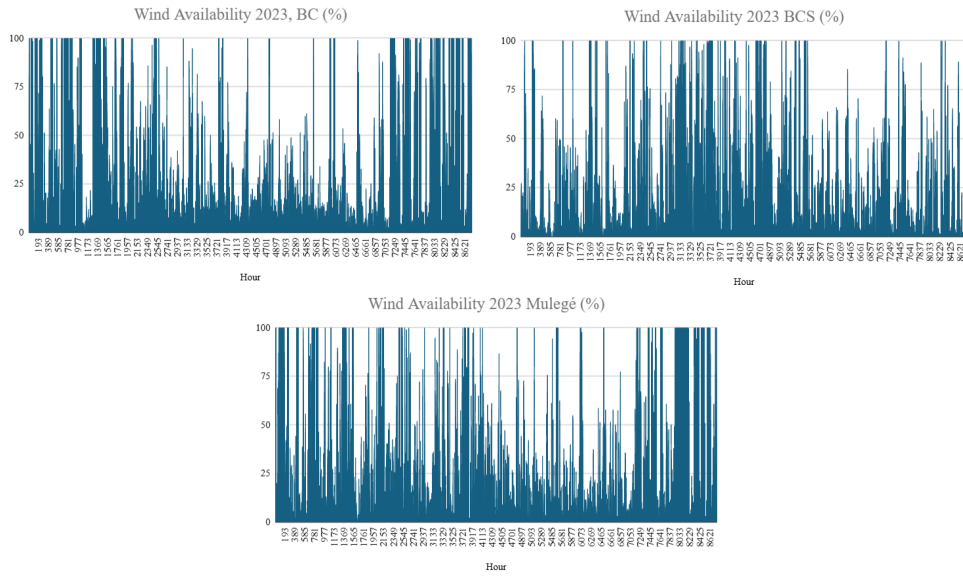


Figure 50: Wind Availability in SIBC, SIBCS and SIM

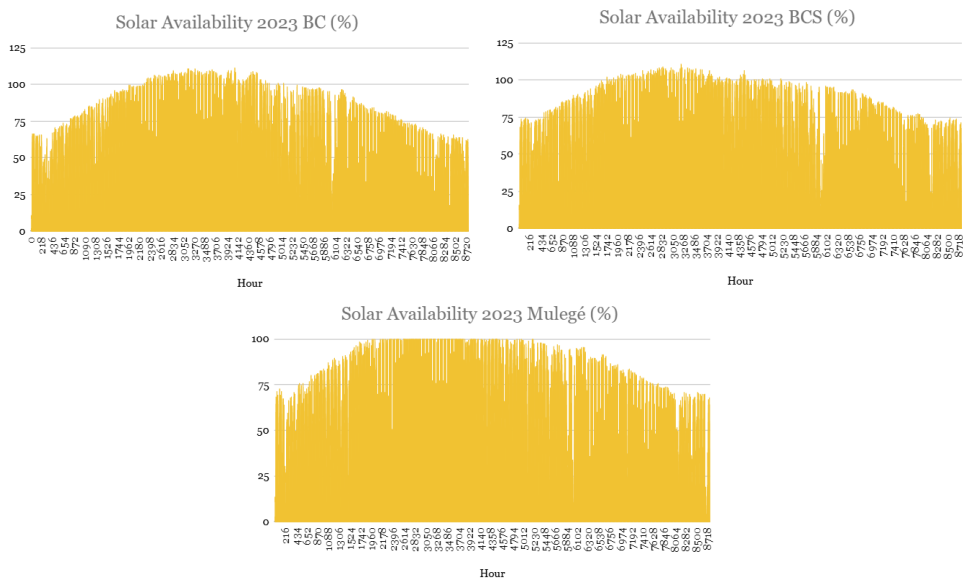


Figure 51: Solar Availability in SIBC, SIBCS and SIM

In the table below the yearly Capacity Factors (CF) for each technology in each system is shown, which are based on the figures above.

Table 19: *The different capacity factors for solar and wind energy in the different areas*

Resource	Year	Area	CF (%)
Wind	2020	SIBC	23.82
		SIBCS	14.71
		SIM	20.47
Sun	2022	SIBC	25.78
		SIBCS	26.30
		SIM	25.75

10.1.8 Supplementary Technology Theory

Turbo gas

A gas turbine power plant, or turbo gas as called in this study, generates electricity by harnessing the kinetic energy from the expansion of compressed air and combustion gases, which drives the turbine blades. The performance of gas turbines is influenced by environmental factors such as temperature, pressure, and humidity, making them sensitive to atmospheric conditions. To standardize their performance, reference conditions are used, such as 15°C temperature, 60% relative humidity, and sea-level pressure. (CENACE n.d.A)

Internal Combustion

An internal combustion power plant (using fuels like fuel oil or diesel) operates based on diesel engine technology. It harnesses the expansion of combustion gases to generate mechanical energy, which is then converted into electricity by a generator. (CENACE n.d.A)

Conventional Thermal

Conventional thermal power plants generate electricity by burning fossil fuels (such as coal, natural gas, or oil) to heat water, creating steam. This steam drives turbines connected to generators that produce electricity. (Elamin, M. 2020)

Combined Cycle

A combined cycle gas turbine power plant increases efficiency by using both gas and steam turbines. The gas turbine generates electricity while its exhaust heats a heat recovery steam generator (HRSG), producing steam to drive a second turbine for additional power generation. This process maximizes energy output and reduces fuel consumption compared to single-cycle plants. (M. Elwardany et. al. 2024)

Geothermal

Geothermal power plants generate electricity by harnessing heat from the Earth's interior. They rely on high-temperature hydrothermal resources, typically between 300°F and 700°F, which can come from dry steam or hot water reservoirs. Deep wells, sometimes extending up to 2 miles, are drilled to access these resources. The extracted steam or hot water is then used to drive a turbine, producing electricity. (EIA 2023b)

Wind Power

Electricity can be generated from wind by capturing its movement and converting it into usable power. Modern wind turbines use large blades that spin when exposed to the wind. This spinning motion is transferred through a shaft to a generator, where it is converted into electrical energy. (IRENA 2024c)

Solar Power

Through solar photovoltaic (PV) technology, solar cells capture sunlight and convert it directly into electrical power. This method provides a clean and renewable energy source, contributing to a reduction in reliance on fossil fuels and helping to lower carbon emissions. Solar power is a key solution for meeting growing electricity demands while promoting environmental sustainability. (IRENA 2024b)

Distributed Generation

Distributed generation refers to the production of electricity from small-scale sources located close to where the energy is used, rather than from centralized power plants. (EPA 2024) In this report, distributed generation specifically refers to solar panels installed at consumer sites, allowing individuals or businesses to generate their own electricity.

Nuclear

Nuclear power is produced by the fission of atomic nuclei, which releases significant heat. This heat is used in reactors to turn water into pressurized steam. The steam then flows through a turbine, causing it to spin and generate electricity through a connected generator. (EIA 2023a)

10.2 Appendix B: Interview Questions

1. Overall Energy Landscape and Current Situation Analysis

What are the biggest challenges and opportunities in the energy system in Baja California for achieving net-zero emissions?

How do you think the distribution of energy sources might change in the future?

What barriers do you see to integrating renewable energy sources into the existing system?

2. Scenarios and Modeling

Which trends or technological advancements do you believe will have the most significant impact on energy consumption and production in the area?

Have you worked with different future scenarios for the energy system? What challenges and opportunities emerged in the various scenarios?

3. Infrastructure and Policy

Which policy decisions do you consider most critical for supporting the transition to net-zero?

What are your thoughts on the need to upgrade or change the infrastructure to handle higher shares of renewable energy?

Are there specific financial incentives that might be necessary to encourage investment in green energy solutions?

4. Economic and Social Aspects

How do the costs of renewable energy sources and technology implementation influence the choice of energy system?

What is your view on the local population's acceptance and involvement in the energy transition?

5. Risks and Uncertainties

What are the major risks and uncertainties that could affect the region's ability to reach net-zero?

10.3 Appendix C: Results

10.4 Capacities 2020-2040

Table 20: Installed Capacity BAS 2020-2040 in SIBC (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NGCC	1821	1821	1821	1821	2444	3067	3127.6	3188.2	3248.8	3309.4	3370	3370	3370	3370	3370	3370	3370	3370	3370	3370	3370
Wind	40	40	40	40	114.9	189.7	264.6	339.4	414.3	489.1	564	916.9	1269.8	1622.6	1975.5	2328.4	2681.3	3034.1	3387	3387	3387
Solar	47	51	51	51	221.3	391.6	561.9	732.1	902.4	1072.7	1243	1243	1243	1243	1243	1243	1243	1243	1243	1243	1243
Geothermal	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570
Internal Combustion	17	17	17	429	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642
Conventional Thermal	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320
Turbo Gas	434	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459
Distributed Generation	0	35.7	71.3	107	133	159	185	211	237	263	289	304.3	319.5	334.8	350	365.3	380.5	395.8	411	411	411
Batteries	0	0	0	0	72	90	108	126	144	162	180	190.6	201.3	211.9	222.5	233.1	243.8	254.4	265	265	265

Table 21: Installed Capacity FOS 2020-2040 in SIBC (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NGCC	1821	1821	1821	1821	2890.3	2890.3	3022	3170.7	3326.3	3493.8	3665.8	3844.2	4034.4	4227.9	4428.9	4620.3	4832.1	5052.6	5279.8	5514.1	5755.6
Wind	40	40	40	40	114.9	189.7	264.6	339.4	414.3	489.1	564	564	564	564	564	564	564	564	564	564	564
Solar	47	51	51	51	651	817	1493.2	1853	2146.7	2204.2	2289.7	2646.7	2789.3	3028.5	3216.1	3968.3	4227.8	4419.1	4616.7	4836.1	5062.4
Geothermal	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570	570
Internal Combustion	17	17	17	429	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642	642
Conventional Thermal	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320
Turbo Gas	434	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459	459
Distributed Generation		71.3	80	107	133	159	185	211	237	263	289	304.3	319.5	334.8	350	365.3	380.5	395.8	411	411	411

Table 22: Installed Capacity REN 2020-2040 in SIBC (GW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NGCC	1.8	1.8	1.8	1.8	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Wind	0	0	0	0	0.1	0.2	0.4	0.7	1.1	1.6	2.2	2.7	3.1	3.3	3.4	3.4	3.4	3.4	3.4	3.4	4.4
Solar	0	0.1	0.1	0.1	0.4	0.5	0.7	1.7	1.9	1.9	1.9	1.9	2.4	3.9	5.4	6.9	8.4	9.9	11.4	12.9	14.4
Geothermal	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Internal Combustion	0	0	0	0	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Conventional Thermal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Turbo Gas	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Distributed Generation	0	0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Batteries	0	0	0	0	0	0	0	0	0	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.9	1.4	2.5	3.6

Table 23: Installed Capacity EXP 2020-2040 in SIBC (GW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NGCC	1.8	1.8	1.8	1.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Wind	0	0	0	0	0.1	0.2	0.4	0.7	1.1	1.6	2.2	2.7	3.1	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Solar	0	0.1	0.1	0.1	0.7	1.2	2.2	3.2	4.2	5.2	6.2	7.2	8.2	9.2	10.2	11.2	12.2	13.2	13.9	14.5	15.2
Geothermal	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Internal Combustion	0	0	0	0	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Conventional Thermal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Turbo Gas	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Distributed Generation	0	0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Batteries	0	0	0	0	0	0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	1.3	2.3	3.3	3.4	3.6	3.7

Table 24: Installed Capacity BAS 2020-2040 in SIBCS (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	25	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Solar	55	78	98	98	135.4	172.9	210.3	247.7	285.1	322.6	360	375.3	390.5	405.8	421	436.3	451.5	466.8	482	482	482
Internal Combustion	343	343	343	352	352	352	352	352	352	352	352	333.9	315.8	297.6	279.5	261.4	243.3	225.1	207	207	207
Conventional Thermal	113	113	113	113	113	113	113	113	113	113	113	98.9	84.8	70.6	56.5	42.4	28.3	14.1	0	0	0
Turbo Gas	315	470	506	606	616	626	636	646	656	666	676	676	676	676	676	676	676	676	676	676	676
Distributed Generation	0	8.7	17.3	26	28.8	31.6	34.4	37.1	39.9	42.7	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Nuclear	0	0	0	0	0	0	0	0	0	0	0	12.5	25	37.5	50	62.5	75	87.5	100	100	100
Batteries	0	0	0	0	38.4	76.9	115.3	153.7	192.1	230.6	269	333.8	398.5	463.3	528	592.8	657.5	722.3	787	787	787

Table 25: Installed Capacity FOS 2020-2040 in SIBCS (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	25	50	50	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Solar	55	78	98	98	198	298	398	500.6	508.9	538.7	547.4	595	625.9	656.2	692.5	885.1	921.8	959.9	999.3	1037	1075.7
Internal Combustion	343	343	343	352	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5	530.5
Conventional Thermal	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Turbo Gas	315	470	506	606	1006	1220.6	1269	1274.9	1371.8	1471.5	1574.8	1674.8	1778.5	1885.9	1997	2110	2229	2352.2	2479.7	2611.8	2748.4
Distributed Generation	0	8.7	17.3	26	28.8	31.6	34.4	37.1	39.9	42.7	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5

Table 26: Installed Capacity REN 2020-2040 in SIBCS (MW)

CAPREN MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	25	50	50	150	150	150	150	150	150	150	150	150	150	150	150	150	350	550	750	950
Solar	55	78	98	98	198	298	398	653	730.7	833.5	957.2	1064.3	1464.3	1864.3	2264.3	2664.3	3064.3	3464.3	3864.3	4264.3	4664.3
Internal Combustion	343	343	343	352	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8
Conventional Thermal	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Turbo Gas	315	470	506	606	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Distributed Generation	0	8.7	17.3	26	28.8	31.6	34.4	37.1	39.9	42.7	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Batteries	0	0	0	0	0	20.8	42.3	64.1	87.1	110.8	135.3	159.1	197.6	308.6	377.3	404.2	433.3	433.3	440	442.1	862.4

Table 27: Installed Capacity EXP 2020-2040 in SIBCS (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	25	50	50	150	150	150	150	150	150	150	150	150	150	150	480.1	880.1	1280.1	1280.1	1280.1	1280.1
Solar	55	78	98	98	198	298	398	653	730.7	833.5	1055.7	1455.7	1855.7	2255.7	2655.7	3055.7	3455.7	3855.7	4066.1	4282.8	4506
Internal Combustion	343	343	343	352	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8	533.8
Conventional Thermal	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Turbo Gas	315	470	506	606	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Distributed Generation	0	8.7	17.3	26	28.8	31.6	34.4	37.1	39.9	42.7	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Batteries	0	0	0	0	0	20.8	42.3	64.1	87.1	110.8	135	195.9	308.7	364.9	376.9	376.9	376.9	765	799.2	834.4	870.6

Table 28: Installed Capacity BAS 2020-2040 in SIM (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	1	1	1	1	2.2	2.5	2.8	3.1	3.4	3.7	4	65.9	127.8	189.6	251.5	313.4	375.3	437.1	499	499	499
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Internal Combustion	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Turbo Gas	14	14	14	14	14	25	36	47	58	69	80	80	80	80	80	80	80	80	80	80	80

Table 29: Installed Capacity FOS 2020-2040 in SIM (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	1	1	1	1	3.5	12.1	12.2	12.2	25	25.9	26	26.7	27.1	27.2	28.3	31.4	32.3	33.2	34	35	35.9
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Internal Combustion	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Turbo Gas	14	14	14	14	71.9	76.2	81.1	86.1	90.4	95.6	101	106.4	112	117.7	123.4	129.2	135.2	141.4	147.6	154.1	160.6

Table 30: Installed Capacity REN 2020-2040 in SIM (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	1	1	1	1	6	16	18.4	24.4	34.4	44.4	50	53.7	58	60.5	64.1	71.1	74.6	78.9	81.7	116.9	166.9
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Internal Combustion	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Turbo Gas	14	14	14	14	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4
Batteries	0	0	0	0	0.6	1.1	1.7	2.6	3.8	6.9	9	10.2	10.7	11.2	11.8	14.1	15.2	16.5	17.1	20.4	31.5

Table 31: Installed Capacity EXP 2020-2040 in SIM (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	1	1	1	1	6	16	18.4	24.4	34.4	44.4	50	53.7	58	60.5	64.1	71.1	107.7	157.7	163.2	168.7	174.3
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Internal Combustion	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Turbo Gas	14	14	14	14	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4	66.4
Batteries	0	0	0	0	0.6	1.1	1.7	2.6	3.8	6.9	9	10.2	10.7	11.2	11.8	14.1	18.6	29.8	30.8	31.8	32.8

10.4.1 Electricity Generation 2020-2040

Table 32: Electricity Generation BAS 2020-2040 in SIBC (TWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Combined Cycle	8.9	9.5	10	9.6	9.7	10.8	11	11.3	11.5	11.8	12.1	12.2	12.3	12.5	12.6	12.7	12.9	13	13.1	13.5	13.8
Wind	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.7	1.2	1.7	2.1	2.6	3.1	3.6	4.1	4.6	4.7	4.8
Solar	0.1	0.1	0.1	0.1	0.4	0.6	0.9	1.1	1.4	1.6	1.9	1.9	1.9	2	2	2	2	2.1	2.1	2.1	2.2
Geothermal	2.2	2.4	2.2	1.9	1.8	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9
Internal Combustion	0.1	0.1	0.1	1.4	1.7	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.8
Conventional Thermal	0.6	0.7	0.9	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Turbo Gas	2.3	2.2	1.8	1.4	1.1	0.9	0.9	0.9	1	1	1	1	1	1	1	1	1	1	1	1.1	1.1
Distributed Generation	0	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7

Table 33: Electricity Generation FOS 2020-2040 in SIBC (TWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Combined Cycle	8.9	9.5	10	9.6	8.2	8.5	7.6	7.6	7.8	8.3	8.9	8.8	9.3	9.6	10.1	9.8	10.3	10.9	11.5	12.2	12.7
Wind	0.1	0.1	0.1	0.1	0.3	0.4	0.6	0.7	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1
Solar	0.1	0.1	0.1	0.1	1.6	2	3.7	4.5	5.2	5.4	5.6	6.5	6.8	7.4	7.8	9.2	9.8	10.2	10.6	11.1	11.6
Geothermal	2.2	2.4	2.2	1.9	2.4	2.4	2.4	2.4	2.3	2.3	2.3	2.2	2.2	2.2	2.1	1.9	1.9	1.9	1.9	1.9	1.9
Internal Combustion	0.1	0.1	0.1	1.4	1.3	1.2	1.1	1	1.3	1.2	1.4	1.2	1.2	1	1	0.8	0.7	0.5	0.3	0.1	0.1
Conventional Thermal	0.6	0.7	0.9	0.8	0.8	0.7	0.6	0.5	0.4	0.2	0	0	0	0	0	0	0	0	0	0	0
Turbo Gas	2.3	2.2	1.8	1.4	1.3	1.1	0.9	0.8	0.8	0.7	0.7	0.7	0.5	0.6	0.5	0.4	0.3	0.2	0.1	0.1	0
Distributed Generation		0.1	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1	1	1

Table 34: Electricity Generation REN 2020-2040 in SIBC (TWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Combined Cycle	8.9	9.5	10	9.6	8.9	9.1	9.2	7.2	6.7	6.5	6.2	6.1	5.5	4	3.2	2.8	2.7	2.5	1.7	0.3	
Wind	0.1	0.1	0.1	0.1	0.3	0.5	0.9	1.6	2.4	3.5	4.8	5.8	6.4	5.8	5.7	5.6	5.5	5.4	5.4	5.3	9.2
Solar	0.1	0.1	0.1	0.1	0.9	1.3	1.6	4.1	4.7	4.7	4.7	4.7	5.8	9.1	11.2	12.9	14.3	15.7	17.8	21	20.5
Geothermal	2.2	2.4	2.2	1.9	2.4	2.4	2.4	2.4	2.3	2.3	2.2	2.1	1.9	1.5	1.3	1.1	1	0.9	0.7	0.4	0.1
Internal Combustion	0.1	0.1	0.1	1.4	1.3	1.2	1.1	1	1.3	1.3	1.1	1	0.9	0.8	0.8	0.6	0.6	0.6	0.4	0.2	0
Conventional Thermal	0.6	0.7	0.9	0.8	0.8	0.7	0.6	0.5	0.4	0.2	0	0	0	0	0	0	0	0	0	0	0
Turbo Gas	2.3	2.2	1.8	1.4	1.3	1.1	0.9	0.8	0.8	0.8	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.3	0.2	0.1	0
Distributed Generation	0	0.1	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1	1	1	1

Table 35: Electricity Generation EXP 2020-2040 in SIBC (TWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Combined Cycle	8.9	9.5	10	9.6	8.2	7.5	5.9	5.1	4.4	4.2	3.9	3.5	3.3	3.1	3	1.6	0.3	0	0	0	0
Wind	0.1	0.1	0.1	0.1	0.3	0.5	0.9	1.3	1.8	2.4	4.1	4.9	5.6	6	6.2	6.3	6.3	6.3	6.3	6.3	6.5
Solar	0.1	0.1	0.1	0.1	1.6	3	5.4	7.4	9	10.1	10.6	11.2	11.7	12.4	13.3	16	18.8	19.3	20.6	21.9	22.1
Geothermal	2.2	2.4	2.2	1.9	2.4	2.4	2.2	1.8	1.5	1.4	1.2	1.1	1	1	0.9	0.7	0.5	0.5	0.3	0.1	0.1
Internal Combustion	0.1	0.1	0.1	1.4	1.3	1.1	0.9	0.7	0.7	0.4	0.1	0.1	0.1	0.1	0.1	0	0	0	0	0	0
Conventional Thermal	0.6	0.7	0.9	0.8	0.8	0.7	0.6	0.4	0.4	0.2	0	0	0	0	0	0	0	0	0	0	0
Turbo Gas	2.3	2.2	1.8	1.4	1.3	1.1	0.9	0.7	0.7	0.4	0	0	0	0	0	0	0	0	0	0	0
Distributed Generation	0	0.1	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1	1	1	1

Table 36: Electricity Generation BAS 2020-2040 in SIBCS (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	0	93	141	56.6	56.8	57.1	57.4	57.8	58	58.3	59	59.7	60.3	60.7	61.1	61.5	61.9	62.2	62.7	63.1
Solar	193	193	218	263	267.4	338.1	408.1	477.7	547	616.3	685.7	725.7	766.9	808.3	850.4	893.5	937.1	980.9	1025.5	1041.6	1057.5
Internal Combustion	1318	1318	992	1112	1004.2	1008.4	1013.2	1018.4	1024.1	1029.1	1033.5	993.2	950.3	904.1	854.7	804.6	753.4	701.4	648.6	653.2	657.6
Conventional Thermal	538	538	543	510	453.1	454.9	457.1	459.5	462	464.3	466.3	413.4	358.5	301.5	242.8	183.3	123	61.8	0	0	0
Turbo Gas	777	777	1091	1231	1139.9	1163.2	1187.4	1212.4	1238	1263	1287.4	1304.4	1319.7	1332	1340.9	1349.8	1358.1	1366.1	1373.9	1383.6	1393.1
Distributed Generation	0	0	0	0	56.8	61.7	66.7	71.6	76.6	81.6	86.6	88	89.3	90.6	91.9	93.2	94.4	95.6	96.8	98.3	99.8
Nuclear	0	0	0	0	0	0	0	0	0	0	80.4	162.7	246.3	330.6	416	502.3	589.4	677.5	682.3	686.9	

Table 37: Electricity Generation FOS 2020-2040 in SIBCS (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	0	93	141	193.3	193.3	193.3	193.3	193.3	193.3	193.3	183.7	179.4	178.8	175.3	157.3	157.3	157.3	157.3	157.3	157.3
Solar	193	193	218	263	454.8	684.4	914.1	1144.8	1164.5	1230.2	1253.2	1365.1	1436.2	1504.6	1585.1	1912.3	1988.6	2067.6	2149.3	2229.7	2312.5
Internal Combustion	1318	1318	992	1112	562.2	265.9	246.8	274.3	267.9	261.7	257.2	253.2	249.6	246	242.3	238.3	234.3	230.2	226	221.6	217
Conventional Thermal	538	538	543	510	353	175.6	157.2	143.8	134	122.9	117.9	109.5	103.5	99.2	95.1	92.1	90.4	89.6	88.8	88.8	88.8
Turbo Gas	777	777	1091	1231	1906.2	2122.6	2055.2	1945.8	2076.4	2168.9	2300.9	2358.9	2453.4	2552.9	2647	2515.7	2620.7	2728.4	2839.8	2958.6	3081.9
Distributed Generation	0	0	0	0	66.1	72.5	78.9	81.5	90	96.3	102.8	102.8	104	103.1	103.8	102.6	102.6	102.6	102.6	102.6	102.6

Table 38: Electricity Generation REN 2020-2040 in SIBCS (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	0	93	141	193.3	193.3	193.3	193.2	193.1	190.2	186.9	186.8	180.6	178.4	169.3	160.1	151.3	421.6	642.4	767	509.5
Solar	193	193	218	263	454.8	684.4	914.1	1468.9	1632.5	1838.7	2076.4	2283.1	2870.4	3545.2	4020.3	4265	4498.7	4434.5	4423.7	4495	5480.9
Internal Combustion	1318	1318	992	1112	507.4	414.4	410.3	311.4	311	304.7	295.4	291	240.9	116.7	59.1	44	48.1	47.6	53.1	0	0
Conventional Thermal	538	538	543	510	338.2	252.3	215.1	158.6	152.4	143.9	133.6	127.7	101.7	82.6	68	66.4	64.7	60	55	53.6	0
Turbo Gas	777	777	1091	1231	1822.6	1897	1838.8	1577.9	1561.7	1519.2	1455.7	1412.5	1071	724.5	510.7	461.4	427.1	400.9	383.1	375.9	0
Distributed Generation	0	0	0	0	66.1	72.5	78.9	85.3	91.7	98.1	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5

Table 39: Electricity Generation EXP 2020-2040 in SIBCS (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	0	0	93	141	193.3	193.3	193.3	193.3	193.1	189.3	185	180.6	178.2	169.9	166.8	160.9	151.4	571.4	537.5	501.5	473
Solar	193	193	218	263	454.8	684.4	914.1	1468.8	1632.5	1839.6	2208.1	2820.6	3489.7	3893.8	4075.8	4022.3	4168.7	5025.4	5312.5	5498.1	5760.4
Internal Combustion	1318	1318	992	1112	524.1	414.4	410.3	311.4	311	304.7	295.4	209.1	83.1	43.1	48.4	37.1	32.3	0	0	0	0
Conventional Thermal	538	538	543	510	385.8	252.3	215.1	158.6	152.4	143.9	122.4	93	77	65	67.2	55.7	47.7	0	0	0	0
Turbo Gas	777	777	1091	1231	1822.6	1897	1838.8	1577.9	1561.7	1519.2	1359.8	1008	661.4	489.3	470.8	406.3	363.3	0	0	0	0
Distributed Generation	0	0	0	0	66.1	72.5	78.9	85.3	91.7	98.1	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5	104.5

Table 40: Electricity Generation BAS 2020-2040 in SIM (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	2	2	1	1	4.2	4.7	5.1	5.6	6	6.4	6.8	55.9	73.9	84.4	92	98.1	104.4	110.2	115.7	117	120.3
Geothermal	37	37	40	47	43.6	42.5	41.5	40.6	39.8	39	38.2	28.9	25.9	24.5	23.7	23.3	23	22.8	22.8	23.1	23.7
Internal Combustion	93	93	96	109	94.4	92	89.9	87.9	86.1	84.4	82.7	62.5	56.1	53	51.4	50.4	49.8	49.5	49.4	50.1	51.8
Turbo Gas	24	24	17	14	12.2	21.2	29.9	38.1	46.1	53.8	61.1	46.2	41.4	39.2	37.9	37.2	36.8	36.6	36.4	37	37.6

Table 41: Electricity Generation FOS 2020-2040 in SIM (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	2	2	1	1	7.9	22.6	23.4	23.4	48.7	50.4	51.9	53.5	54.8	54.9	56	60.1	60.1	60.1	60.2	61.7	61.8
Geothermal	37	37	40	47	52.6	49.4	49.6	50.2	50.8	50.7	50.6	50.6	51	51.2	50.4	50.9	51.3	51.7	51.7	51.7	52.1
Internal Combustion	93	93	96	109	84.2	64.3	64.1	64	16	16.5	16.8	17	16.6	16.4	16	15.4	15.2	15.1	14.9	14.7	14.5
Turbo Gas	24	24	17	14	23.7	35.7	38.5	41.7	67.6	69.4	71.5	73.8	76.9	80.8	84.2	85.8	89.9	94.2	98.5	102	106.5

Table 42: Electricity Generation REN 2020-2040 in SIM (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	2	2	1	1	13.5	36.1	41.5	53.4	77.3	97.4	108.9	116.4	123.7	128.6	135	148.7	155.8	164.1	169.4	208	235.6
Geothermal	37	37	40	47	52.3	44.8	43.8	40.6	45.3	44	43.5	42.8	41.8	41.4	40.7	37	35.7	33.7	33.2	15	5.1
Internal Combustion	93	93	96	109	84.2	63.7	63.6	62.5	16.8	11.3	9	8.2	7.9	8	7.9	5.6	5.1	4.3	4.4	1	0
Turbo Gas	24	24	17	14	18.4	27.6	27	23.4	44.3	35.6	31.2	29.5	27.7	27.3	26.2	23.2	22.7	21.9	21.7	10.5	0

Table 43: Electricity Generation EXP 2020-2040 in SIM (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar	2	2	1	1	13.5	36.1	41.5	53.4	77.3	97.4	108.9	116.4	123.7	128.6	135	148.7	194.2	224.4	231	237.7	244.3
Geothermal	37	37	40	47	52.3	44.8	43.8	40.6	45.3	44	43.5	42.8	41.8	41.4	40.7	37	16.1	5.2	5.2	5.1	5
Internal Combustion	93	93	96	109	84.2	63.7	63.6	62.5	16.8	11.3	9	8.2	7.9	8	7.9	5.6	0.9	0	0	0	0
Turbo Gas	24	24	17	14	18.4	27.6	27	23.4	44.3	35.6	31.2	29.5	27.7	27.3	26.2	23.2	10.7	0	0	0	0

10.5 Appendix D: Sensitivity Analysis

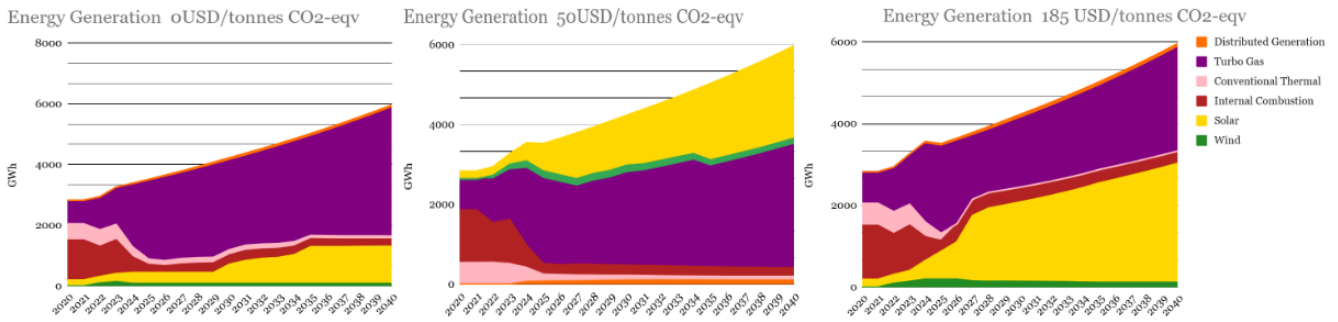


Figure 52: Difference in generation 2024-2040 of the SCC sensitivity scenarios in SIBCS

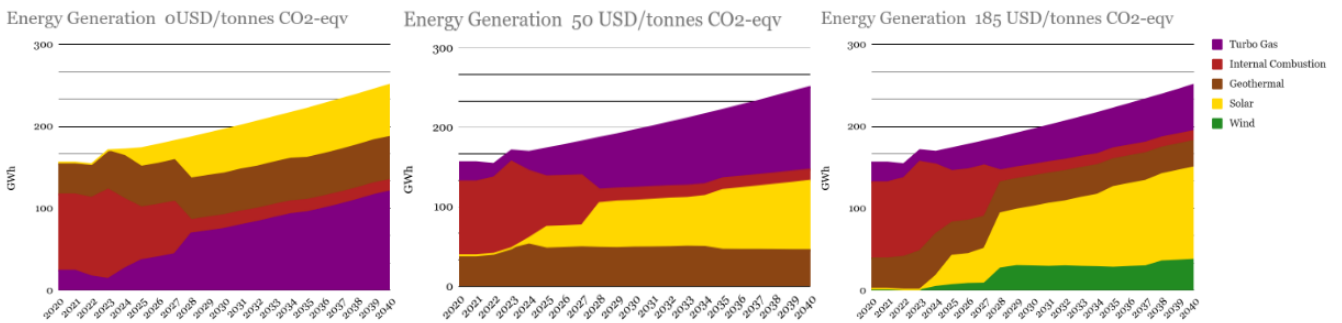


Figure 53: Difference in generation 2024-2040 of the SCC sensitivity scenarios in SIM

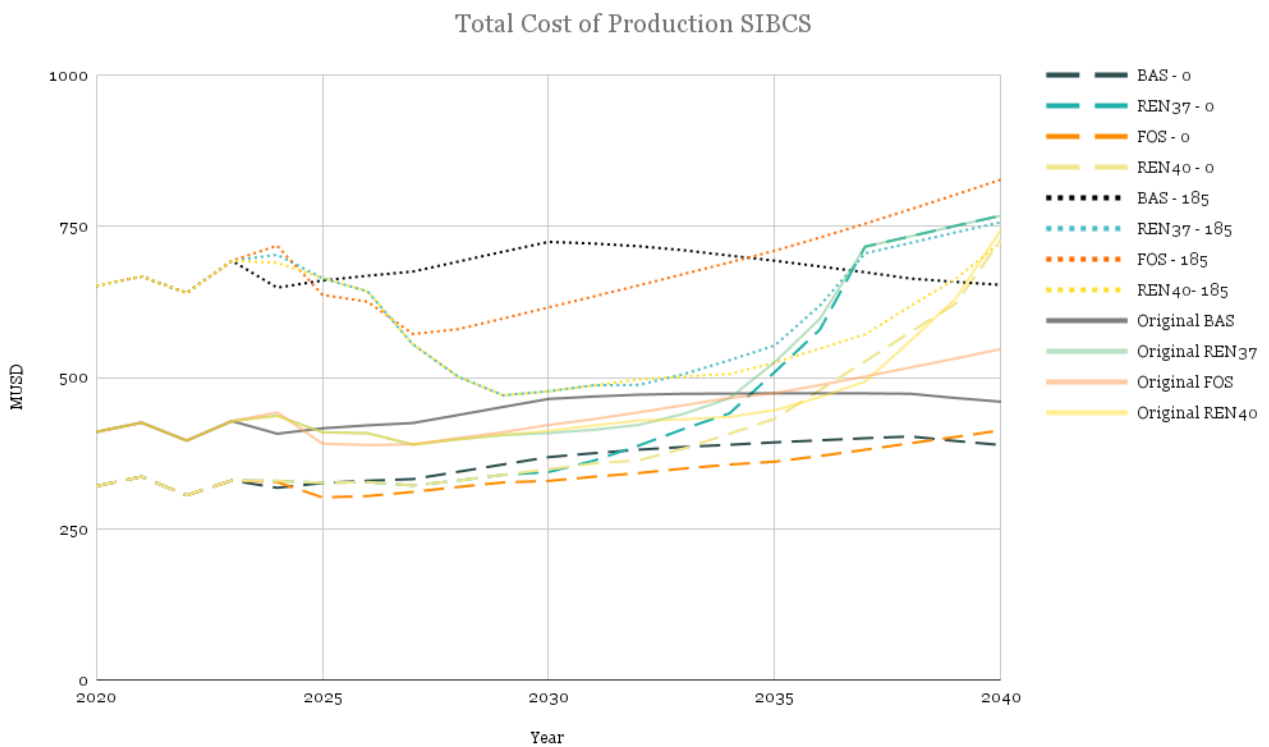


Figure 54: Total Cost of Production of the SCC sensitivity scenarios in SIBCS

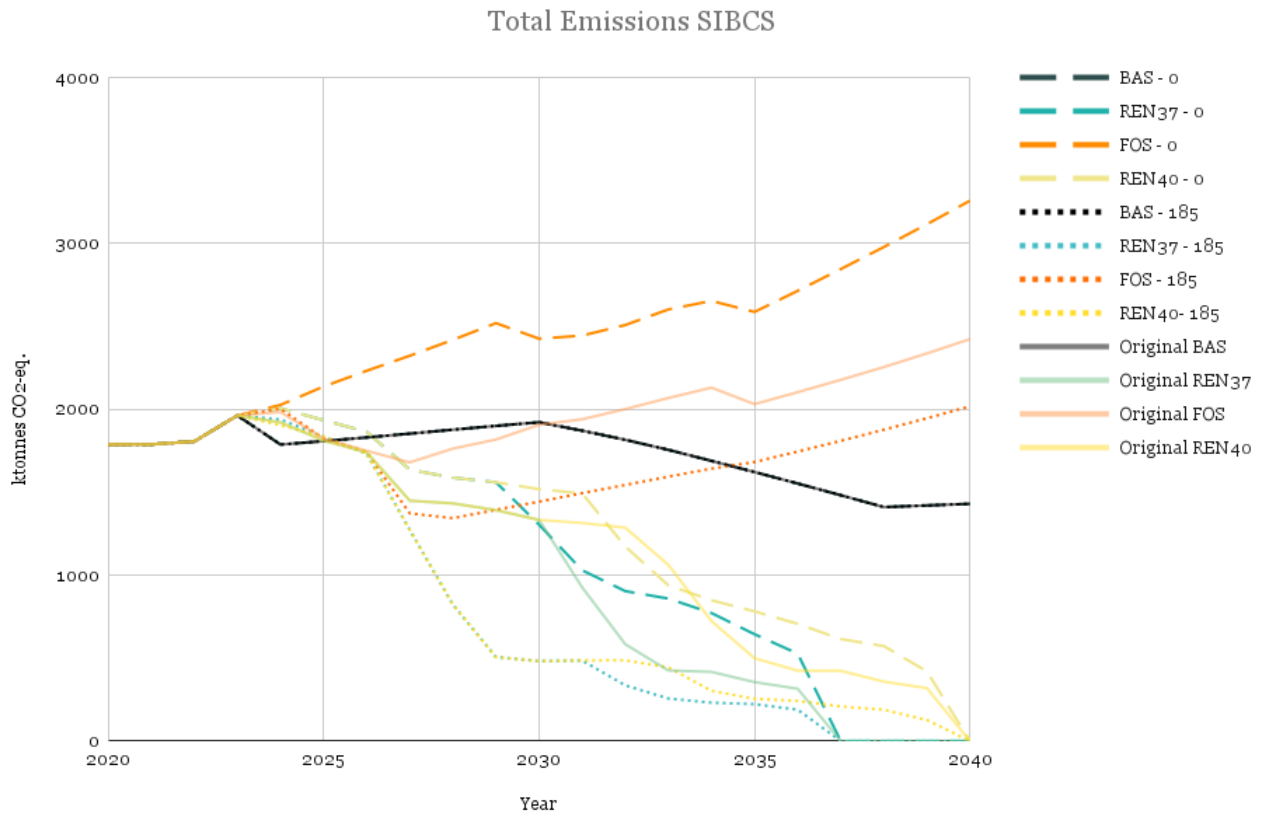


Figure 55: Total Emissions of the SCC sensitivity scenarios in SIBCS

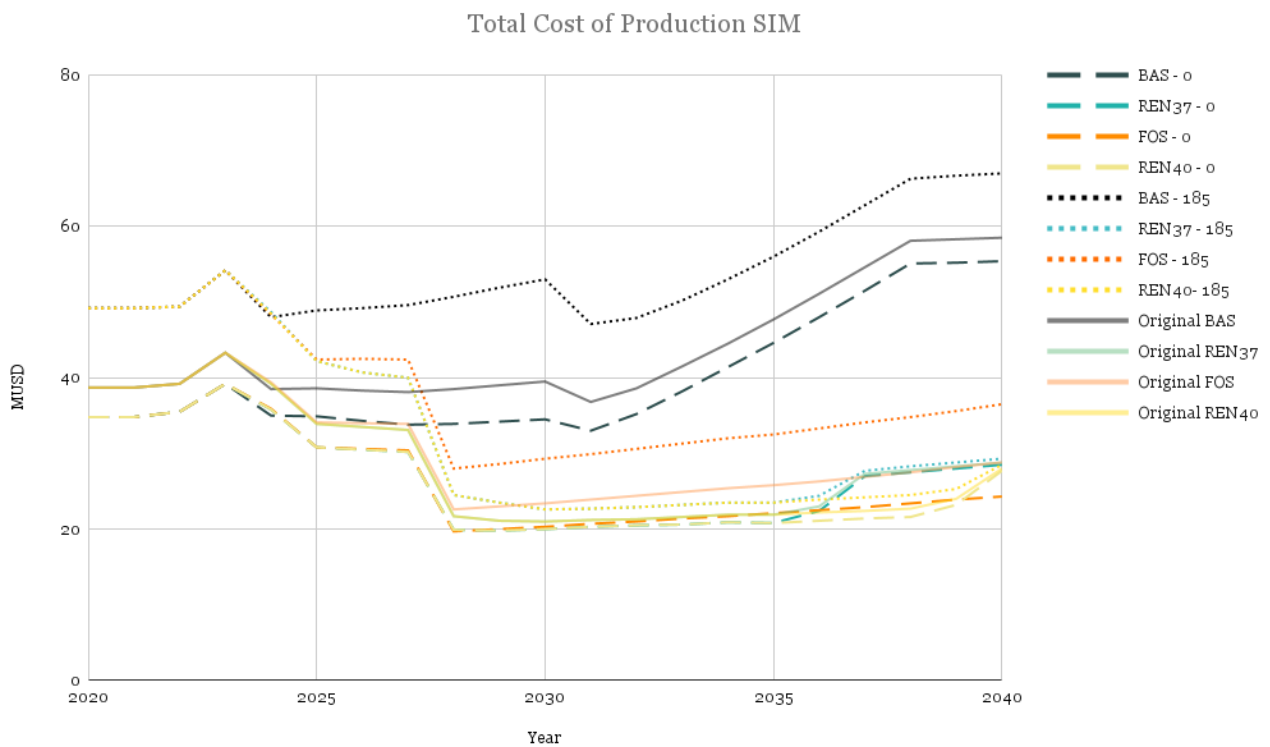


Figure 56: Total Cost of Production of the SCC sensitivity scenarios in SIM

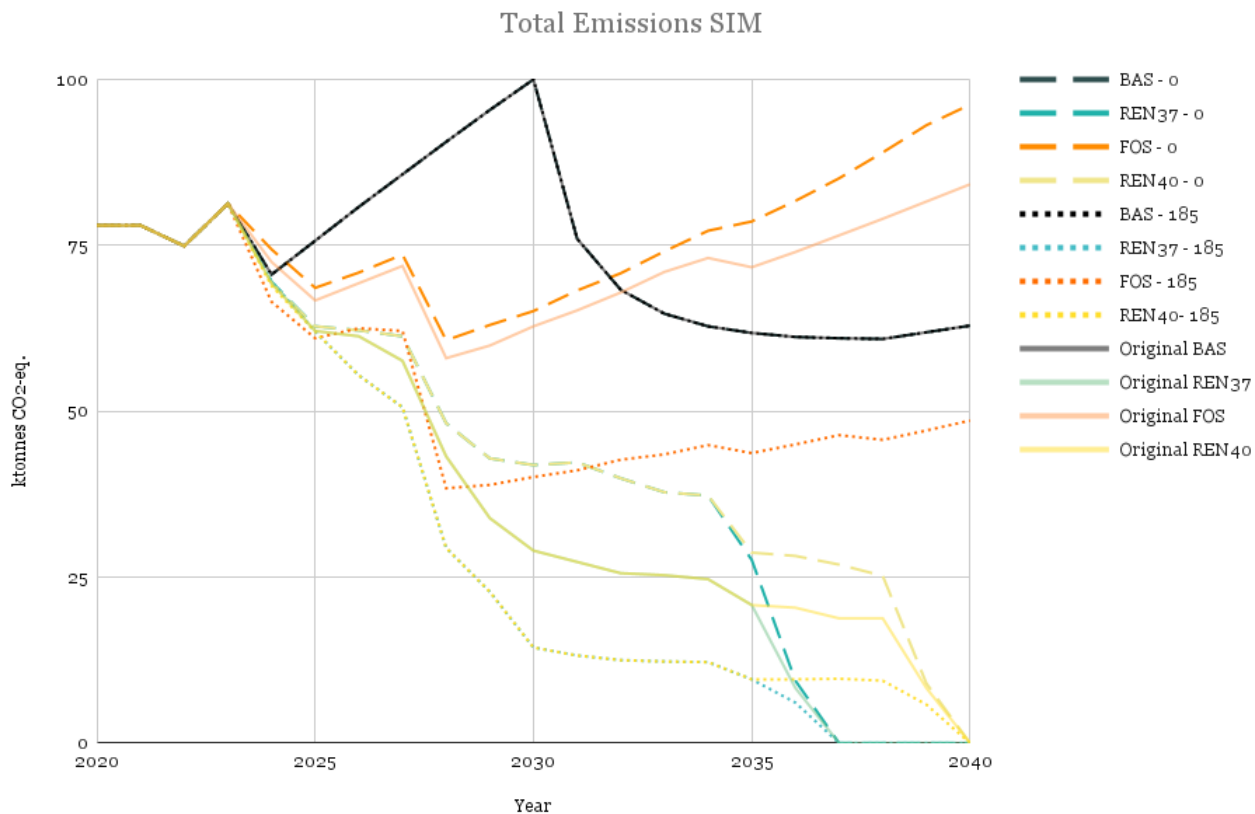


Figure 57: Total Emissions of the SCC sensitivity scenarios in SIM

10.6 Appendix D: Data Validation Costs

Table 44: *Difference in cost for technologies depending on source*

		INECC	NREL	
NGCC	Capital Cost	1023	1472	USD/kW
	Fixed OM	19,18	26-79	USD/kW/year
	Variable OM	3,33	2,16-5,35	USD/MWh
Wind	Capital Cost	1750	1607	USD/kW
	Fixed OM	38,47	32-40	USD/kW/year
	Variable OM	0	0	USD/MWh
Solar	Capital Cost	1400	1435	USD/kW
	Fixed OM	10,8	22,2	USD/kW/year
	Variable OM	0	0	USD/MWh
Geothermal	Capital Cost	1908	4687-6200	USD/kW
	Fixed OM	106,12	120-159	USD/kW/year
	Variable OM	0,1	0	USD/MWh
Turbo Gas	Capital Cost	921	-	USD/kW
	Fixed OM	5,15	26	USD/kW/year
	Variable OM	4,85	6,94	USD/MWh